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TAKING OVER A RIVER SYSTEM WITH HYDRO ASSETS

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ABSTRACT

MIIKA TUOVINEN: Taking over a river system with hydro assets
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Hydropower as a renewable, storable and flexible energy production form is well-suited for responding to the fluctuating power demand. Since hydropower covers more than 50 % of the total Nordic electricity production, its availability is a significant price driver in the Nordic electricity markets. Hydropower producers aim to maximize profits in long term when scheduling their production allocation to different market places. Hydropower planning is a continuous process that starts from long-term planning and ends with real-time operating of hydropower units. Day-ahead market is the most important marketplace for hydropower companies but they benefit also from participating in other energy and capacity markets. Hence, hydropower profitability can be increased by trading in intraday and balancing power markets in which producer is required to be able quickly decide which bids are carried out in the markets.

This thesis focuses on hydropower intraday activities of a control room in Finland. All activities are related to a single river system that was previously unknown for the control room. The main purpose of this thesis was to give support to the learning process of the river system but also consider how profits can be increased during intraday. In order to do so, the properties of the river system were studied, modelled and implemented into different tools. In successful hydropower activities, it is also question whether the personnel who are responsible for intraday production scheduling and operating of hydro units are familiar with the river system. The training process for the personnel is presented in this thesis.

The main result of this thesis is a method for hydropower bidding curve calculation for intraday energy markets. The method determines marginal cost of available trading capacity based on the deviation costs that arise when production is adjusted from the original production plan. The method enables producer to quickly estimate how much and at what price it is profitable to buy or sell its hydro production in the intraday markets.

This thesis also suggests that profitability can be increased by automated monitoring of intraday market with relation to hourly production capacity. Monitoring enables control room to find feasible bids from the market place but also evaluate the opportunity cost for a production increase or decrease.

TIIVISTELMÄ

MIIKA TUOVINEN: Vesistöalueen ja sen vesivoiman haltuunotto
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Vesivoima uusituvana, varastoitava ja joustavana tuotantomuotona pystyy hyvin vastaamaan nopeastikin vaihtelevaan sähkön kysyntään. Vesivoima kattaa yli puolet kaikesta energiantuotannosta Pohjoismaissa ja siten sen saatavuus onkin merkittävin yksittäinen hintatekijä Pohjoismaisilla sähkömarkkinoilla. Vesivoiman tuotannonsuunnittelu on jatkuva prosessi, joka alkaa pitkänaikavälin suunnittelusta ja päättyy vesivoimaloiden reaaliaikaiseen operoimiseen. Vesivoimatuottajat pyrkivät maksimoimaan tuottonsa allokoimalla vettä kalleimmille ajanjaksoille. Spot-markkina on tärkein markkinapaikka tuottajille, mutta myös muut markkinat lisäävät vesivoimatuottajien kannattavuutta. Vesivoiman päivänsisäisen kannattavuuden lisäämisen keskiössä on kaupankäynti päivänsisäisillä energiamarkkinoilla, joilla toimiessaan tuottajan on nopeasti pystyttävä päättämään, millä hinnalla se on valmis lisäämään tai vähentämään tuotantoa.

Tämä diplomityö käsittelee suomalaisen energiavalvomon vesivoiman päivänsisäistä tuotannonsuunnittelua ja kaupankäyntiä. Tarkasteltava vesistöalue ja sen pääuoman vesivoimalaitokset ovat entuudestaan tuntemattomia energiavalvomon henkilökunnalle. Diplomityön avulla pyrittiin tukemaan henkilökunnan oppimisprosessia ja lisäämään päivänsisäistä arvonluontia. Sen vuoksi vesistön ominaisuuksia tutkittiin ja mallinnetiin tarvittaviin työkaluihin. Energiavalvomon toiminnan kannalta on tärkeää, että tuotannonsuunnittelusta ja operoinnista vastaavat operaattorit tuntevat vesistön. Diplomityössä esitetään henkilökunnan koulutusprosessi.

Diplomityössä luotiin menetelmä, jolla voidaan muodostaa tuotannon tarjoamiskäyrä päivänsisäisille energiamarkkinoille. Menetelmä huomioi käytettävissä olevan tuotantokapasiteetin ja sen marginaalikustannuksen perustuen kustannuksiin, jotka aiheutuvat tuotantotason muuttamisesta alkuperäisestä tuotantosuunnitelmasta. Menetelmän avulla voidaan nopeasti arvioida millä hinnalla tuotantoa kannattaa lisätä tai vähentää.

Diplomityössä esitetään myös, että kannattavuutta voidaan lisätä Nord Poolin Intraday markkinan automatisoidulla monitoroimisella. Monitoroinnissa on huomioitava käytettävissä oleva tuotantokapasiteetti, jotta voidaan löytää sopivia tarjouksia markkinapaikalta ja toisaalta, arvioida päivänsisäisen tuotannon lisäämisen tai vähentämisen vaihtoehtoiskustannusta.

PREFACE

This thesis has been written to UPM Energy and for the department of the Electrical Engineering of Tampere University of Technology.

I would like to thank UPM Energy for giving me this opportunity to work with an interesting project that develops not only my understanding of hydropower but also overall activities of energy producer. I would also like to thank my supervisor M.Sc. (Tech) Matti Vuorinen for giving guidance and instructions throughout the project. Furthermore, I would like to thank the rest of the group that work in energy trading center at Tampere. Many thanks to the examiner, Sami Repo from Tampere University of Technology, for all the interest and comments that helped and simplified my work.

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Tampere, April 25th 2019

Miika Tuovinen

CONTENTS

ABBREVIATIONS

aFRR	automatic Frequency Restoration Reserves, also referred as FRR-A
API	Application Programming Interface
BM	Balancing power market
BRP	Balance Responsible Party
CET	Central European Time
DA	Day-ahead market, also referred as Elspot
DSO	Distribution system operator
EDI	Electronic data interchange
EET	Eastern European Time
Elbas	Continuous intraday market for physical electricity trading
Elspot	Day-ahead market for physical electricity trading
EMS	Energy Management System
FCR-D	Frequency Containment Reserve for Disturbances
FCR-N	Frequency Containment Reserve for Normal operation
Hour Unit (HU)	Hydropower discharge hour unit, 1 HU = 3600 m^3
ID	Intraday market, also referred as Elbas
Nasdaq OMX	Trading house for financial contracts
NBS	Nordic Balance Settlement
Nord Pool	Market place for physical electricity trading
NTC	Net Transfer Capacity
mFRR	manual Frequency Restoration Reserves, also referred as FRR-M
OCS	Operations Control System
PX	Power Exchange
RE	Retailer
ROR	Run-of-river type of hydropower
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity
vRES	variable Renewable Energy Resource
XBID	Cross-Border Intraday Initiative Market

1. INTRODUCTION

1.1 Background

Hydropower is a mature, efficient and a renewable source of electricity. On Nordic level, it is dominant production form of electricity because it accounts for more than half of the joint Nordic electricity production (Nordic Energy Regulators 2014). In addition to this important role that hydropower has in Nordic electricity production, quick-adjusting hydropower offers balancing and power reserves that are needed in the Nordic power system and watercourse regulation that is needed in flood protection.

In Nordics, physical electricity is traded in sequential markets; day-ahead, intraday and balancing power markets. Most of the electricity exchange takes place at the electricity wholesale markets, called day-ahead market, where the trade form is a closed auction. In that market place, producer needs to decide how much energy it can produce and at what price hour by hour for the next day. Similarly, buyers need to assess how much energy they need and how much they are willing to pay for that energy. (Nord Pool 2018a) Intraday market is a supplementary market for the day-ahead market where trading can be done continuously until close to the hour of delivery. Hence, it gives an opportunity to market participants to trade off imbalances or unfortunate day-ahead commitments but also make profit. In Nordics, balance responsible parties (BRPs) have the financial responsibility for imbalances between expected generation and expected consumption of their energy portfolio. Imbalance power is priced based on the activations carried out by Transmission System Operators (TSOs) in real-time balancing power market which is cleared shortly before the period of delivery but only if needed. (Scharff et al. 2014; Scharff & Amelin 2016) Due to hydropower production properties, Nordic hydropower producers are actively participating in the balancing markets to gain more profit with their available capacity. (Skjelbred et al. 2017)

It is assumed that the importance of efficient and reliable balancing and reserve markets are growing due to increasing share of intermitted renewable energy production such as wind power in the grid and stronger market connections. (Skjelbred et al. 2017) Hence, markets such as intraday or balancing power markets that are cleared after day-ahead market, might become more and more important for market participants' profitability. Increasing gaining opportunities in different market places for flexible hydropower production increase the complexity of a hydropower producer's decision process since decisions in one market could decrease possibilities in other markets. In theory, all of the subsequent markets should be taken into account before bidding in the first market (Klaboe & Fosso 2013).

Since trading of energy in intraday market and balancing power market is continuous, hydropower producers, like any other market participants, need to do fast but reasonable decisions on their bids that are carried out in the markets. When operating in those markets, hydropower plant have different boundary conditions such as environmental permit conditions and obligations in other market places that need to be taken into account. (Skjelbred et al. 2017) Boundary conditions determine how production can be re-scheduled and thus they set boundaries to available trading capacity. Then producers need to determine prices for the capacity: at with price it is willing to generate more energy or willing to produce less energy, respectively. Hydro production pricing is based on the opportunity cost, typically called water value, that is basis for decision to use water now versus saving it for later generation (Lave & Perekhodtsev 2006). Water value of reservoir is depended on expected reserve and energy prices, water inflow and parameters of a hydropower unit. (Lave & Perekhodtsev 2006; Gebrekiros et al. 2013). Prices can be perhaps forecasted but are not precisely known beforehand. Moreover, actual inflow to the reservoir might differ from the forecasted inflow. Therefore, it can be concluded that hydropower producer needs to deal with uncertainties when participating in deregulated Nordic electricity markets.

1.2 Objectives

This thesis is a research related to taking over of previously unknown river system. The aim is to examine how Intraday Traders of a control center can create additional value with their intraday trading decisions. To fulfill this aim, the river system need to be studied carefully and implement its properties as accurately as possible to different tools that are needed for instance to production optimization and generating of intraday market bids. Moreover, the persons dealing with the river system planning and operating must be familiar with these properties.

The river system's production is sold to the Nordic electricity markets. The objective of the thesis is to consider market places which are cleared during intraday; how production could be bid to balancing power and intraday markets. These markets are denoted from here to throughout the thesis simply as intraday markets when discussing both markets concurrently. To be able generate bids that are actually feasible and profitable, there is a need to examine factors of hydro system that either limits or increases the flexibility of production.

In intraday markets, hydro producer generally faces the following questions:

1. How much energy can be sold or bought and at what price from the markets?
    a. Are the environmental limits followed?
    b. Are the other markets' obligations followed?
    c. What is the marginal cost of production?
    d. What is the water value of the reservoirs?
2. How much capacity can be offered to reserve markets and at what price?
3. How production is scheduled once an intraday bid is accepted?

With respect to part 1, intraday energy markets can be used in profit gaining, reducing of balance power price risk, and to fulfill the day-ahead market obligations that are not attractive in the eyes of the hydro producer. All of the limiting factors and hydro system properties such as hydro units' discharge to power function and water movement in river bed must be modelled accurately in the optimization and bidding tools in order to be able to add value through intraday trading decisions.

Previously unknown hydro system increases the challenges that the hydro operator faces. Hence, this thesis considers how hydro system's properties can be learned; what is the process for trainings of personnel?

This thesis aims to answer to the part 1 presented above. Therefore, it does not focus on overall bidding strategies, i.e. it will not give answer whether the hydro system bidding strategy should be coordinated. The emphasis is merely on developing method that can be utilized in bidding for a single intraday energy market such as balancing power market.

1.3 Structure

The first two chapters explain the theoretical background of this thesis. Chapter 2 introduces Nordic power systems and physical markets. Potential market places for hydro production from energy to balancing and reserve markets are explained. Additionally, the chapter introduces how prices are formed in these different markets. Finally, the chapter gives an insight to markets' price levels and volumes.

Chapter 3 focuses on hydropower production. The chapter begins with the explanation of the intrinsic physical fundaments of hydro production, and continues with a presentation of different types of hydropower plants. In addition, the hydrological environment of Nordic region is presented. Finally, the chapter focuses on production scheduling and explains the operational decision making process of Finnish hydropower producer with focus on day-ahead and intraday planning.

Chapter 4 starts with short problem description of this thesis. In addition, relevant parties and their responsibilities are introduced. The chapter continuous with a description of the studied water system with its hydropower plants and main reservoirs. This chapter also contains a presentation of the constraints that limits production planning and operating. Once, the previously mentioned topics are covered, the chapter presents how the marginal water value of a reservoir can be converted into the marginal cost of a hydro plant. This chapter also presents the procedure that was used in learning of river system's features and properties. The chapter ends with a presentation about the background of intraday hydro activities of the hydro system in question that pulls the problem description of this thesis together.

Chapter 5 focus on intraday bidding and re-scheduling. It begins with a presentation on the premise of intraday trading: timeline for the day-ahead and intraday markets is presented. In addition, the flexibility of the studied hydro system is discussed from an intraday point of view. The chapter also presents how intraday bidding curve can be determined for a hydro plant based on the deviation costs that arise when altering from the original production plan. Finally, the chapter illustrates how intraday market monitoring can be utilized to form energy price-volume curves (opportunity cost) for hydropower production increase and decrease.

Conclusions is expressed in final chapter 6. The chapter provides a review on the main results of the thesis with discussion on possible future development of the hydro system's intraday energy trading. Conclusion also emphasizes the importance of the automation in intraday energy trading.

2. ELECTRICITY EXCHANGE IN NORDICS

Nordic power markets have evolved and expanded since the 1996's when the first international electricity market was opened in Nordic between Sweden and Norway. (Nord Pool 2018d) Over the past two decades, this Nordic market has been broaden to cover multiple countries including all the Nordic and Baltic countries. In addition to the geographical growth, new markets have opened for trading. Nowadays it is possible to trade energy and power reserves in physical markets but also hedge electricity price in financial market. Physical trading activities relay on the power system which is jointly operated by national Transmission System Owners (TSOs') in the Nordic and Baltic. Power system sets some technical limitations to trading and thus influence electricity price. Electricity market participants can hedge their sell and purchase price with power derivatives in Nasdaq OMX.

The purpose of this chapter is to give an outlook to the Nordic power exchange; its electricity exchange and power system. The chapter begins with a review of the Nordic power system and electricity production of the Nordic region. Additionally, Nordic physical power exchange is discussed with respect to available market places and their working principle. In the end of the chapter, there is a short insight on the available market places historical volumes and prices that emphasizes bidding problem of a hydro producer.

2.1 Nordic power system

Nordic power system is a synchronous system which includes systems in Finland, Sweden, Norway and Eastern Denmark. Furthermore, the Nordic system is connected via direct current transmission links to the Baltic countries, Russia and Continental Europe.

Electricity is a commodity which is commonly produced elsewhere than consumed. Moreover, production and consumption need to be in balance every time. Electricity has some unique features which makes it different from other commodities since it is needed exactly as much it is consumed and it is transferred immediately when produced. In Finland, electricity is transferred and distributed via transmission grid, regional networks and distribution networks to electricity consumers. The Finnish transmission grid is owned and operated by Finnish TSO, Fingrid, whose responsibility is to manage transmission and also maintain system's voltage and frequency nation-wide all the time respect to security requirements like N-1 criterion. N-1 criterion is used in grid planning and operating of the transmission network in Nordic countries; The power system withstands one normal individual fault and the disconnection of a faulty component in meshed high voltage grid (400 kV or 220 kV) without interruption in electricity delivery (Fingrid 2017f). Fault that has the largest impact on the power system is the dimensioning fault. The dimensioning fault is time depended. In Finland it could be either fault on a transmission line between neighboring country, fault of the largest power unit or a substation fault. (Entsoe 2017b; Fingrid 2015) In order to maintain secure operation, TSO needs to balance both active power and reactive power. The former influences in the frequency of the system and the latter influences the voltage of the system. In the grid, there are reserves for both types of power. In this thesis, the transmission network is discussed only briefly because it is out of the scope. Therefore, the reactive power reserves are not discussed in this thesis.

Nordic power system has an important role in electricity exchange in Nordics since its condition constrains zonal electricity flow. TSO's in each Nordic country, decides the number of bidding areas in the country (Nord Pool 2017b). For example, Finland constitute one bidding area but in Norway there are five bidding areas. By dividing Nordics into bidding areas TSOs' ensure that their own responsibilities for system stability are fulfilled and thus the regional conditions are reflected in the electricity exchange. (Entsoe 2017b; Nord Pool 2017b) Each TSO calculate Total Transfer Capacity (TTC) which is maximum active power that can be transmitted between the areas with respect to N-1 criterion. However, that capacity cannot serve the commercial electricity exchange in full. TSO's determines The Net Transfer Capacity (NTC) for commercial transfer which is determined by reserving some of the total capacity as a Transmission Reliability Margin (TRM). (Entsoe 2017b; Fingrid 2015) At the moment, Transmission Reliability Margin for Swedish-Finnish northern connection is 100 MW (Fingrid 2015). In Figure 1 is presented bottlenecks in commercial transmission capacity from Finland's point of view in year 2017. The dark blue indicates the area of bidding zones which have shared a common day-ahead price and the percentage how many hours in year 2017. Electricity wholesale market is the place where area price for each bidding area is determined. This market is discussed later in the chapter 2.2.1

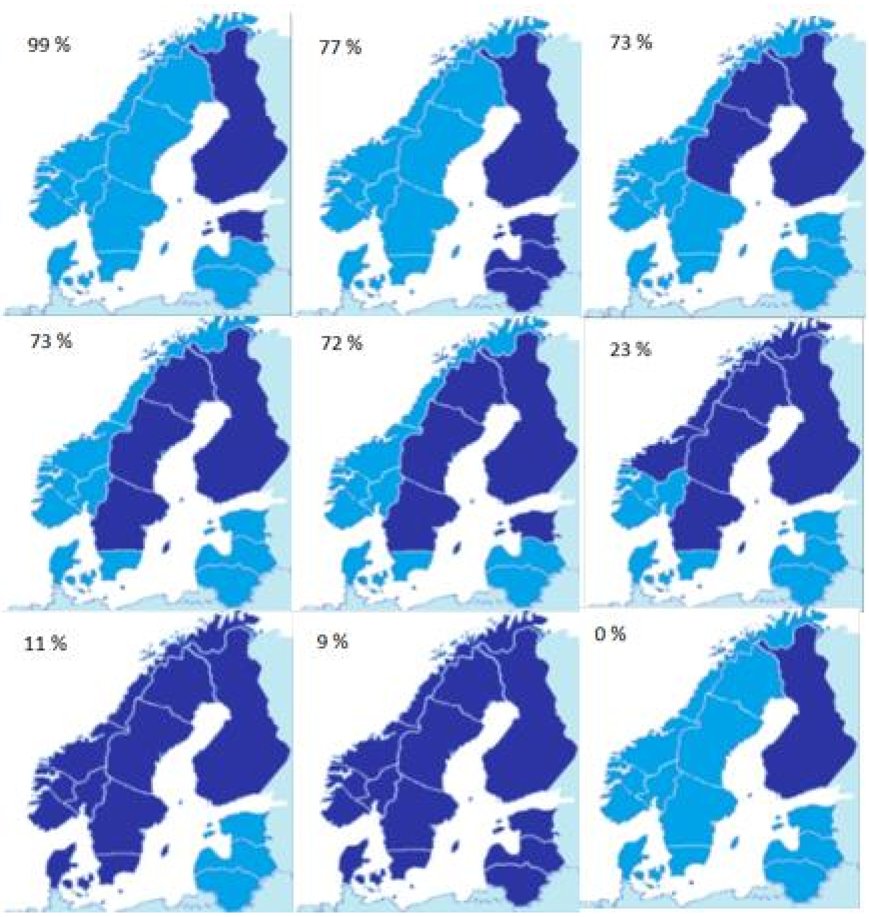

Figure 1. *Integrity of price areas from Finland bidding area perspective in 2017 (Fingrid 2018b).*

As Figure 1 shows, Finland's bidding zone is rarely separated from others. If there is no enough transmission capacity between Finland and bidding zones SE1, SE3 and EE, Finland is a separate price area. All the bidding areas and power flows between them in 28.8.2018 at 7:46 CET are presented in Figure 2.

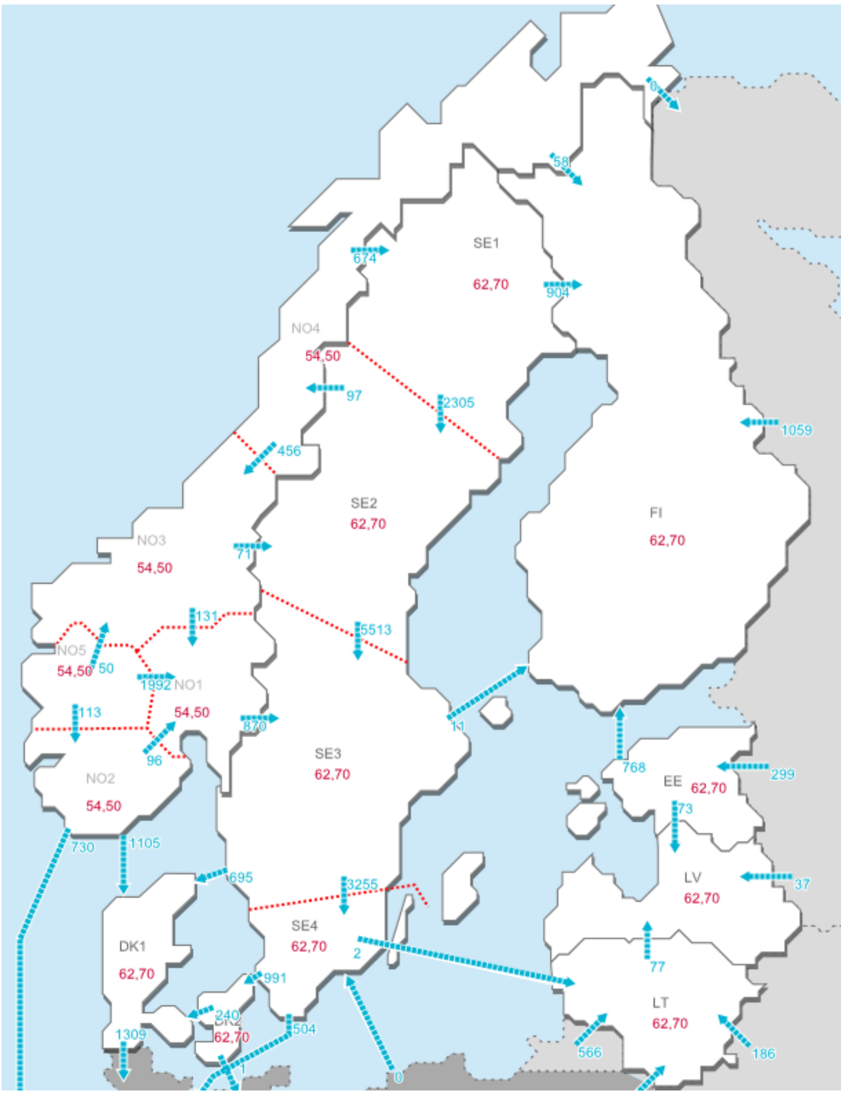

Figure 2. *Nordic power market bidding areas and power flows 28.8.2018 at 7:46 CET (Statnett 2018).*

From Figure 2 we can see that common Nordic power system is beneficial to the society. Considering commercial electricity flow, the electricity always flow from low demand area to an area where the demand is greater and thus the price is higher (Nord Pool 2017b). Therefore, both consumers and producers benefit when power is transmitted between bidding areas. Consumers can buy the needed power cheaper and producers get more money from the power sold. For example in year 2016, roughly fifth of Finnish electricity consumption was covered with imported electricity (Energia 2017).

Nordic power system differ from all other European power system when considering electricity consumption and production. Historically low electricity price have resulted in relatively high electricity consumption in Nordics compared to other European countries. Nordics with large share of cost-effective hydropower and nuclear power have been desirable to energy intensive industry and electricity heated houses. (Nordic Energy Regulators 2014) Based on statistics provided by (Entsoe 2017a) over 75 % of the Nordic electricity production were covered with hydro and nuclear power in 2015 (see Fig. 3). Nordic electricity price is highly depended on hydro availability since cost-efficient hydropower is dominant power production type with over 50 % market share in a normal hydrological year.

However the production of hydropower is not distributed equally in Nordic countries. In Norway, generated electricity comes fully from hydropower. Finland and Sweden have a fair share of hydropower but also nuclear, thermal and renewable power are in major roles in electricity production. As for Denmark, there are nearly nil hydropower production and therefore electricity is produced with thermal and wind power. (Nord Pool 2017c)

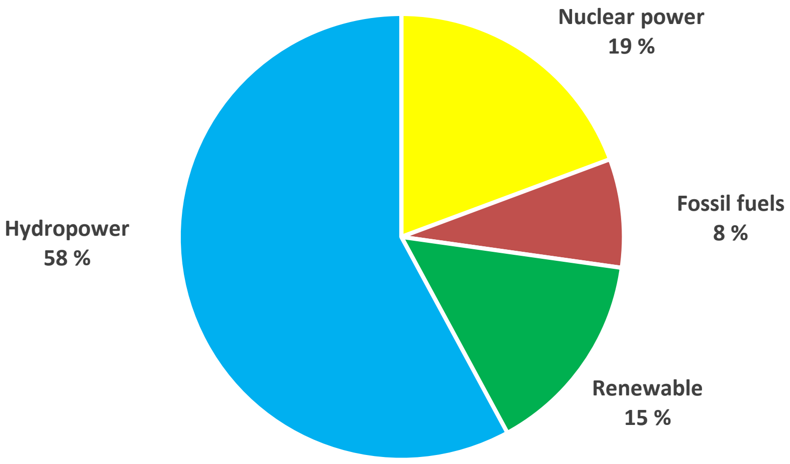

Figure 3. *Nordic electricity production split in 2015 (Entsoe 2017a).*

In Nordics, the electricity price drivers are the availability of low-variable and low cost production (hydro, wind, nuclear) and electricity heating demand. As stated earlier, hydropower is the backbone of Nordic power production. Hydropower has the ability to storage energy in hydro reservoirs which smoothens electricity price curve of the Nordic region. Reservoirs can be utilized to level down inflow variations and water stored in the reservoirs can be used during winter when demand raises due to the increase of heating and lighting demand. Hydropower availability expectations or forecasts for the future will influence the price. For instance, in case of heavy water inflow and low storage capacity, the price level will decrease. Nuclear power, with extremely low fuel costs, is produced as a base load production and therefore its availability is reflected in the price. Wind power in turn will decrease electricity price when available since it has no fuel costs. (Nordic Energy Regulators 2014)

2.2 Physical power exchange

As with any other commodity, electricity price reflects supply and demand. Usually higher demand increases the price of the commodity, and in case of electricity, that is caused by higher marginal costs of production. When it comes to electricity, production and consumption needs to be in balance every moment, but it's not possible that markets could balance generation and consumption in real time since both fluctuates continuously in the power system. For that reason, electricity price is either formed before or after the operating hour. (Wangensteen 2006) In Nordics there two physical markets for the near future physical trading, commonly known as the wholesale market: Nord Pool Elspot, for day-ahead trading and Nord Pool Elbas for intraday trading. Those are used in defining the electricity price beforehand. As for afterwards (or in reality in real-time), balancing carried out in the regulation power market set the price for each hour. The balancing power market is discussed in the chapters 2.3 and 2.4.4.

Nord Pool, previously known as Nord Pool Spot, provides market places for physical electricity exchange. This world's first international electricity market was established in 1996 for Norwegian-Swedish power exchange. Today Nord Pool is owned by the Nordic and Baltic TSO's. Nord pool's day-head trading covers Nordic and Baltic countries but also UK while continuous intraday trading is enabled in thirteen countries: the Nordic, Baltic, German, Luxembourg, French, Dutch, Belgian, and Austrian markets. (Nord Pool 2018a; Nord Pool 2018b; Nord Pool 2018d)

Both of the Nord Pool's market places provide place for market parties to sell and buy electricity, although their purpose, operational principle and thus price formation is divergent. In both markets, market members have no counterparty risks since physical trading as well as physical delivery is done anonymously i.e. the centralized counterparty is Nord Pool (Nord Pool 2019). Both day-ahead and intraday markets are elaborated in the following sub chapters.

2.2.1 Day-ahead market

Day-ahead market is driven by the plans of electricity producers and consumers. For instance, hydro producer need to decide how much can energy be produced and at what price, hour by hour for next day. Nord Pool's day-ahead market is based on closed action: buyers and seller can change their next day orders until 12:00 CET when the auction is closed. After closing, Nord Pool aggregates orders into hourly curves for supply and demand to determine area prices for each of the bidding areas. If there are no constraints in the transmission capacity, electricity price will be congruent in all areas. In this case system price would be the same as the area price of any bidding area. The system price formation does not consider any bottlenecks that constraints trading capacity between bidding areas. The system price is then determined as the intersection of the aggregate supply and demand curves representing all sale and purchase orders for entire Nordic region. The system price is used as the Nordic reference price for trading and clearing of most financial contracts. (Nord Pool 2017b; Nord Pool 2018a) Finnish area price in comparison to daily average system price is presented in Figure 4.

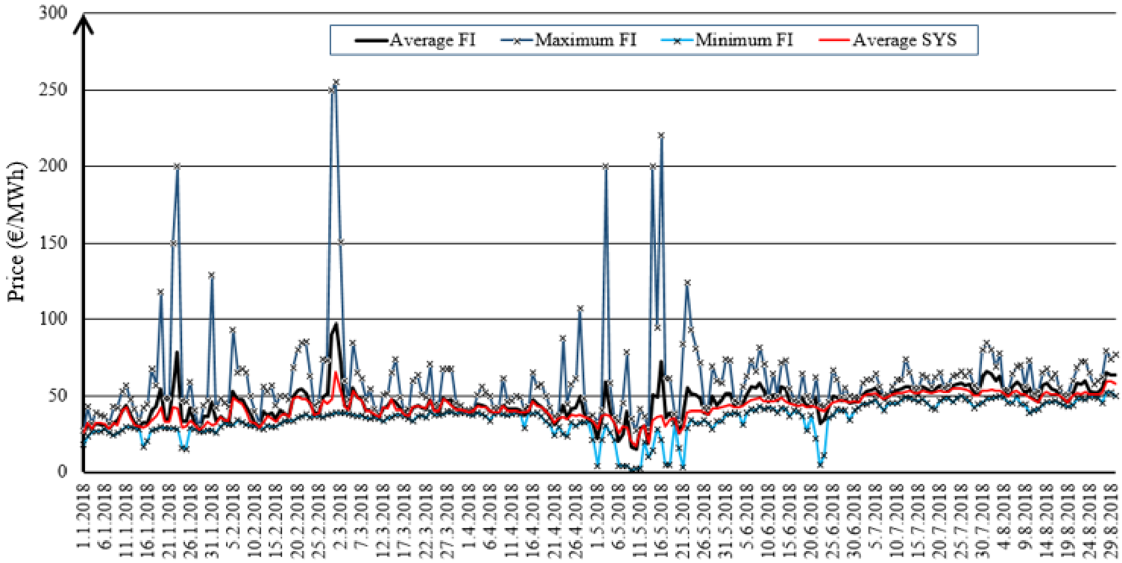

Figure 4. *Finnish area (FI) price presented as daily minimum, average and maximum price and average system price in 1.1. – 13.8.2018 (Nord Pool 2018c).*

Due to transmission constraints, Finland average area price (black curve) differs occasionally clearly from the system average price (red curve) as shown in Figure 4. The highest difference between those in the time period was in 28th February 2018 when the Finland average area price was 42,62 €/MWh higher than the average system price. However, during the time period the difference between the average prices have been less than 1 €/MWh in 45 % of the days.

Area price in Finland has been very volatile in the period shown in Figure 4, showing multiple price-peaks of around 200 €/MWh and lowest prices close to zero at night-time. These can be seen from the presented daily minimum and maximum prices of Figure 4.

2.2.2 Intraday market

Intraday market is a supplementary market for day-ahead market. It is a continuous market in which electricity trading takes place every day around the clock until shortly before to the hour of delivery. The purpose of the market is to ensure that the necessary balance between supply and demand in the Nordics can be secured close to the real-time. Most of the electricity is traded in the day-ahead market, but incidents like power plant failures or stronger wind generation than estimated, can happen after day-ahead market closure, but before the actual delivery hour. In Nordics, market participants can trade until the hour before the delivery to bring back the balance between consumption and production. This is also the case for Finnish market participants when considering Nordic cross-border trading. However, in Finland, market participants can trade until half hour before the delivery hour but only internally and Baltics if there is available transmission capacity left in FI-EE connection. (Nord pool 2018b; Nord pool 2018e)

The hours of day-ahead period are opened for intraday trading once day-ahead results have been cleared and transmission capacities available for intraday trading are published at 14:00 CET by relevant TSO's. Prices are set based on a first-come, first-served principle, where best prices come first, i.e. bids with highest buy price and lowest sell price are firstly met. (Nord Pool 2018b) However, continuous trading means that trades are settled within a time period whenever a market participant accepts an offer of another market participant. Therefore, prices can vary from trade to trade. (Scharff & Amelin 2016)

Intraday trading can be considered profitable by market participants for different reasons. First of all, it is a possibility to reduce imbalance costs which market participants are exposed every time when they have a deviation between actual and planned supply. Especially, reducing of market participants imbalance volumes is a way to hedge against uncertain imbalance costs that might be significantly deviating from day-ahead prices. (Scharff & Amelin 2016) Imbalance settlement is described in the chapter 2.3.

Another reason is the possibility to optimize production or consumption schedule. As an example, producer can buy energy and thereby reduce generation in an own power plant that would be more costly to run. Additionally, since day-ahead bid is based on estimations on marginal costs, the day-ahead market could lead to unwanted commitments such as one hour odd start or stop of generation unit. Thus producer may be willing to trade out the unfortunate commitment. (Scharff & Amelin 2016; Klaboe & Fosso 2013)

Finally, intraday trading can be used for gaining profits: a market participant can use it to offer flexibility in own production or consumption to others who are willing to pay more than the respective marginal cost of running and re-scheduling of the corresponding power plants and dispatch-able loads. In addition, all power plants and dispatch-able loads cannot meet the requirements of balancing power or reserve markets and hence it might be only possibility to gain profits by flexibility of production or consumption. (Scharff & Amelin 2016) Balancing power market is discussed in the chapter 2.4.4.

According to a survey about trading behavior on the continuous intraday market (Scharff & Amelin 2016), intraday market volumes varies from price zone to price zone. They base their discussion on the Nord Pool's intraday market data from 2.3.2012 – 28.2.2013. The most likely factors behind the trading volumes are penetration of variable renewable energy resources (vRES), limited transmission capacity and imbalance cost. Denmark with the highest vRES penetration in the Nordics, trades most energy in the intraday market when the trading volumes are considered as relation to country's generated energy. High volumes are not only caused by vRES, because in Finland, the vRES penetration is considerably low in relation to the total energy generation whereas the traded volumes are considerably high in the same relation. This could be result of noticeably higher risk of uneconomic imbalance prices than in the Swedish and Norwegian price zones. Balancing power prices are more moderate in the price zones with predominant hydropower generation and significant hydro storage capabilities than in price zones SE3, SE4, FI and DK2. Moreover, limited transmission capacity might decrease intraday trading possibilities. Finland and Denmark are likely to face limited possibilities to buy energy from Swedish and Norwegian price zones on the intraday market. (Scharff & Amelin 2016) It should be noticed that the survey's market data is quite old and therefore the market's trading behavior, production structure and trading motivations might have changed.

Intraday markets are broaden due to the Cross-Border Intraday Initiative Market (XBID) solution which is a project which was started as a joint initiative by the different Power Exchanges (PXs) such as EPEX SPOT and Nord Pool with the TSO's from 11 counties. With XBID, orders entered by market participants for continuous matching in one country can be matched by orders submitted by another market participants in any other country within the project's countries as long as there is transmission capacity available. The objective of the XBID is to extend the mechanism for cross-border intraday trading to all Europe and potentially to interconnected countries. The introduction of XBID is carried out in three phases of go-live. First phase took place in June 2018 when 14 countries were included. Countries were Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden. (Nord Pool 2018f)

2.3 Balance power

Every market party must take care of its power balance continuously. In practice, deviations occur and electricity market party cannot balance its electricity balance completely by itself. Therefore, every market party is obligated to have an open supplier which handles the party's power imbalance. In Finland, imbalance settlement is done via chain of open suppliers, and the highest party of the chain is Fingrid. A market participant whose open supplier is Fingrid's Balance Service Unit is called a balance responsible party (BRP). This open delivery between Fingrid's balance service unit and balance responsible party is agreed with balance service agreement. Balance responsible party takes care of the imbalance settlement within its balance responsibility (Fingrid 2017c). Electricity retailer or simply retailer (RE) is an electricity market party who perform electricity trading activities such as selling electricity to an end user or other retailer. Every retailer has to have an agreement either with a balance responsible party or with another retailer who has an agreement with BRP for open supply. (eSett handbook 2017) Figure 5 shows the chain of open supply.

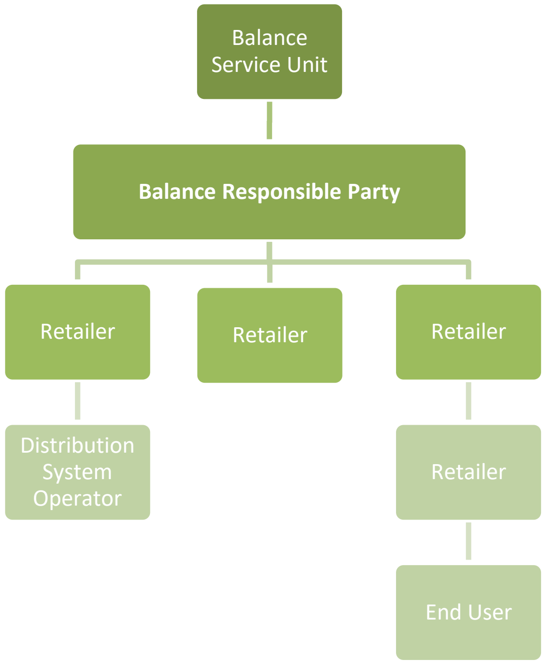

Figure 5. *The chain of open supply.*

Error in power balance leads to open supply. The imbalance settlement defines hourly open deliveries between parties operating in the electricity market. The data for the settlement is provided by distribution system operators (DSO) who are obligated to meter hourly electricity production, consumption and transmission between other grids in addition to reporting the metered data to the involved market parties. The metered data is used to compare each party's predetermined plans with actual ones. Since 1^{st} of May 2017 imbalance settlement service have been outsourced to a company called eSett Oy. eSett is a service company, established and jointly owned by Nordic TSO's (Fingrid, Statnett and Svenska Kraftnät), which handles imbalance settlement at the transmission system level in Finland, Sweden and Norway. The company uses a common harmonized imbalance settlement model that is result of a project Nordic Balance Settlement (NBS) implemented by relevant TSO's. It is though noteworthy that by national regulations each national TSO is still responsible for own area balancing operations and balance settlement. (eSett Handbook 2017)

Power balance of BRP is calculated and settled separately for both production and consumption imbalance. Imbalance power is bought from Fingrid in case of deficit and correspondingly imbalance power is sold to Fingrid in case of surplus. Moreover, imbalance power price system differs between production imbalance and consumption imbalance according to activation done in the balancing power market maintained by Fingrid (see chapter 2.4.4). If there have not been any regulation during the operation hour, the price of imbalance power is the hour's day-ahead price. The imbalance power price determination is illustrated in Figure 6. It shows how production and consumption imbalance prices are determined depending on regulation carried out in the specific hour.

	Production balance 2-price			Consumption balance 1-price			
	Up-regulating hour	No regulations	Down-regulating hour	Up-regulating hour	No regulations	Down-regulating hour	
Up-regulating price	100	50	50	100	50	50	€/MWh
Spot price	50	50	50	50	50	50	€/MWh
Down-regulating price	50	50	20	50	50	20	€/MWh
Fingrid's sales price for balance power	100	50	50	100	50	20	€/MWh
Fingrid's purchase price for balance power	50	50	20	100	50	20	€/MWh

Figure 6. *Determination of imbalance price (Fingrid 2017c).*

Balance responsible party delivers hourly production plan to Fingrid including all power units. This production plan need to be reported to Fingrid 45 minutes before the beginning of the specific hour. Production imbalance is determined based on balance responsible party's total production plan, power imbalance adjustments and actual production. In Finland, all generators over 1 MVA are part of production balance but smaller generators are handled either in consumption balance or production balance depending what balance responsible party is requesting. (Fingrid 2017c) Actual production imbalance can be calculated with equation:

Production - Planned production -/+ Production imbalance adjustment
= Production imbalance power.

Production imbalance arises when actual production deviates from planned. The imbalance power is priced with two-price system in which sales and purchase price of imbalance power are valued differently if there have been regulation during the hour as can be seen from Figure 6. The price for balance responsible party's production imbalance deficit is always the up-regulation price of the hour. In the example above that is either 50 €/MWh or 100 €/MWh. As for balance responsible party's production surplus, the price used is always the down-regulation price, i.e. maximum the Spot price.

BRP's consumption balance composes of its total production plan, fixed transactions, consumption imbalance adjustments and actual consumption. If forecast consumption deviates from actual consumption balance imbalance arises. Unlike production imbalance power, consumption imbalance power price is always market areas' imbalance power price. (Fingrid 2017c) Consumption imbalance is defined with equation:

Consumption - Planned production -/+ fixed transactions -/+ Consumption imbalance adjustments = Consumption imbalance power.

Balancing power price creates a price risk for market participants since it's not known before or even during operation hour. According to Nordic balancing philosophy (Entsoe 2016), preliminary regulation power prices are not currently published during operation hour because BRP's self-regulation could disturb balancing process carried out by TSO's. Although down-regulation have been more common than upward regulation in recent years in Nordics, the price risk is higher for upregulating. Since September 2015, there have been four times when all Finnish up-regulating balancing bids from the balancing power markets have been activated to cover power deficit. Extremely, the balancing power price raised up to 3000 €/MWh in 22nd January 2016 for one hour due to a cold weather and low volume of upregulating balancing bids (580 MW). However, there have been sometimes shortage of down-regulating bids especially during importing and night hours in Finland. Occasionally the balancing power becomes slightly negative. However, in 7th May 2017 the balancing power price became extremely negative due to transmission system testing in Sweden causing a bottleneck situation between Finland and Sweden along with lower realized consumption and higher realized production. The balancing price became -500 €/MWh for two hours and -1000 €/MWh for four hours. (Fingrid 2016c, Fingrid 2017g, Fingrid 2017k) Obviously it is profitable to many energy consumer to offer consumption increase through balancing power market with negative price. When the price gets negative enough, it provides good gaining possibility also for energy producers.

Some of the market participants have an edge over other market participants since they have knowledge about the balancing power price. This knowledge comes when their bid is accepted in the balancing power market. It enables market participant to manage its' balances cost-effectively. (Fingrid 2017e) According to the balance agreement between Fingrid and BRP, balance responsible party are not allowed to use open supply for systematic power purchases or deliveries (Fingrid 2017b), even though it might increase its profits. Market participant that have surplus or deficit in its consumption balance might benefit if the hour's imbalance price is favorable in relation to its balance error. This can be seen from Figure 6. Moreover, according to the agreement, the hourly imbalance should be reasonable with respect to BRP's scope of operations.

2.4 Power reserves

When considering active power in Nordics, market parties responsibility is to plan their production and consumption to be in balance beforehand. Unavoidably both realized production and consumption deviates from forecasts and therefore system's frequency fluctuates around nominal frequency which in Nordics is 50 Hz. When consumption is greater than production frequency is lower than nominal value and correspondingly, when production exceeds consumption the frequency is higher than nominal value. (Fingrid 2017d)

Frequency has to keep in a certain level in order to maintain power system operation and thus regulation is needed. In the synchronous system, Fingrid has agreed to maintain reserves in collaboration with other Nordic TSO's. (Fingrid 2017d) Frequency control processes that are used in Finland for balancing a momentary difference between electricity production and consumption during each hour are presented in Figure 7.

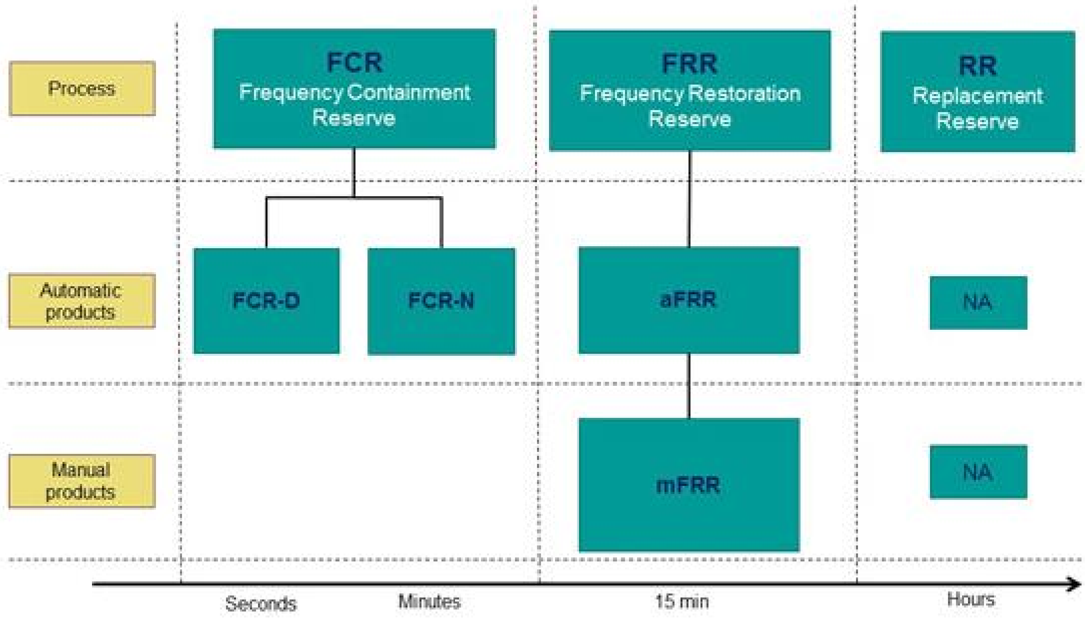

Figure 7. Frequency control processes in Finland (Fingrid 2017d).

Processes are divided into following three categories. Frequency Containment Reserves (FCR) are used to control frequency constantly. Frequency Restoration Reserves (FRR) objective is to return frequency to normal range and release FCR back to use. Respectively, Replacement Reserves (RR) are used to release activated FRR back to state of availability in case of new disturbances. (Fingrid 2017d)

Some of these reserves switch on automatically if the grid's frequency starts deviating from its nominal frequency and the rest are ordered manually by the relevant TSO. The activation time of reserve varies from seconds to hours depending on the purpose of the power reserve. (Fingrid 2017d)

2.4.1 Operation of reserves

When frequency starts deviating from the nominal value, frequency containment reserves for normal operation (FCR-N) are automatically activated. The purpose of FCR-N is to adjust grids frequency so that it stays between 49,90 Hz and 50,10 Hz which is considered as normal state of frequency. This type of reserve need to be able adjust its active power almost linearly according to frequency. The FCR-N capacity needs to be fully activated in 3 minutes when frequency changes ± 0,1 Hz or more from 50 Hz. In Nordic power system, there is jointly maintained 600 MW of Frequency Containment Reserve for Normal operation. This volume is divided between each areas based on previous year electricity consumption. (Fingrid 2017a; Fingrid 2017d)

When there is deficit of the active power in the power system that FCR-N capacity is not capable to maintain frequency above 49,90 Hz, reserves for disturbances are activated. The purpose of FCR-D is to stabilize the frequency in case of disturbance so that the steady state frequency is higher than 49,50 Hz. When frequency drops below normal state, FCR-D needs to almost linearly increase its active power until is increased linearly until frequency of 49,50 Hz. If frequency drops step-wisely to at least 0,5 Hz, full activation must be done in 30 seconds and half of the capacity need to be activated in 5 seconds. The volume of maintained FCR-D in Nordic power system depends on a dimensioning fault. In normal operation, maintained volume is enough to keep frequency in 49,5 Hz or above in case of dimensioning fault. Although the needed volume of disturbance reserves in Nordic power system in normal situation is 1200 MW, it is 200 MW less than dimensioning fault because of self-regulation of frequency depended load in the system. Distribution of volume between the subsystems is set in proportion to each area's dimensioning fault and the distribution is updated at least once a week. (Fingrid 2017a; Fingrid 2017d)

In order to restore and maintain frequency in normal state, frequency restoration reserves (FRR) are needed. The purpose of FRR is to restore the frequency to its nominal value and thus release activated frequency containment reserves back into use. In difference to frequency containment reserves which react to frequency deviations locally, restoration reserves are centrally controlled by TSOs. In Nordics, the mostly used restoration reserve is manually activated manual frequency restoration reserve (mFRR) despite the fact that new automatically activated product called automatic frequency restoration reserve (aFRR) was introduced in January 2013. The aFRR can be seen as automated implementation of manual frequency restoration reserve in the restoration process although its supports the frequency much faster than mFRR. The aFRR needs to be activated fully in 2 minutes while mFRR's full activation need to be achieved in 15 minutes. Regardless of activation method, these products work similarly; depending on the power balance situation (current or forecasted) the relevant TSO activates up or down balancing bids submitted by resource owner. Up balancing power can be either production increase or consumption decrease and it is needed in case of active power deficit. Respectively, down regulation power is used to remove power surplus from the power system and it's carried out with production decrease or consumption increase. (Fingrid 2017d; Entsoe 2016)

To visualize operation of described power reserves, Figure 8 presents frequency containment process for an under frequency situation. As Figure 8 illustrates, FCR increases active power in grid so that frequency stays above 49,50 Hz at a steady state. Then FRR activation is carried out and the frequency is restored back to the normal state.

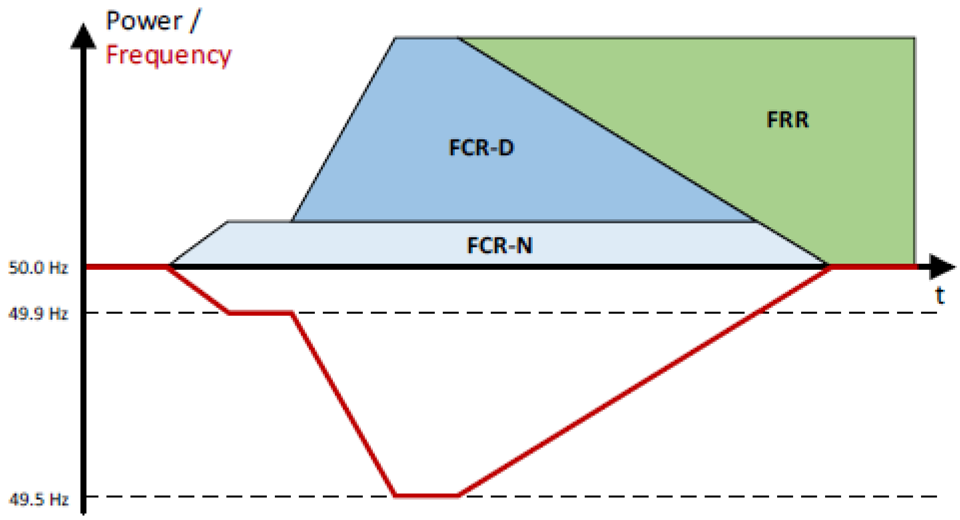

Figure 8. *FCR and FRR processes during an under frequency situation (Entsoe 2017c).*

2.4.2 Procurement of the frequency containment reserves

Fingrid procures its FCR obligation from domestic markets and some of it from other Nordic countries. The trading between other countries is limited. Finnish TSO, like any other Nordic TSO's, can procure the maximum of one third of its FCR volume from other Nordic countries. Thus most of the frequency containment reserves have to be provided nationally to maintain frequency in isolated operation. In addition, the Russian and Estonian direct current transmission links can be used as procurement channel for FRC-N. Fingrid's obligation for FCR-N and FCR-D is 140 MW and 260 MW respectively. (Fingrid 2017d)

Domestic reserve markets are maintained by Fingrid. Production or consumption capacity that fulfills the reserve requirements and is located in Finland, can be offered to the reserve markets. Separate hourly and yearly market exist for both frequency containment normal operation and disturbance reserves. Both markets share the same technical requirements. Reserve holder does not have to be the owner of the reserve but must have a consent of the owner for reserve. Moreover, reserve bid may also be aggregated from several balances. Minimum reserve capacity, also minimum bid size, that is sufficient for both yearly and hourly FCR-N and FCR-D markets is 0,1 MW and 1 MW respectively. (Fingrid 2017a; Fingrid 2017d)

Yearly market is organized once a year as a bidding competition for the next calendar year. The bidding competition is arranged in September-October. The fixed price for all accepted reserves is set by the most expensive bid accepted in the yearly market. Reserve holder whose reserve capacity is accepted in yearly market, is obligated to provide tomorrows available reserve capacity with the fixed price to Fingrid. In order to receive the fixed price per provided reserve capacity, reserve holder supplies hourly reserve plans to Fingrid at an accuracy of 0.1 MW. The reserve volume stated in the reserve plan can be at most equal to the volume agreed between Fingrid and reserve holder. The period of the reserve plans is always next day Elspot period i.e. 01:00 – 01:00 EET. These plans for the next day-ahead period must be submitted to Fingrid in EDI messaging using DELFOR message format by 6.00 pm EET, otherwise the reserves are not accepted (Fingrid 2017a).

Hourly market is also based on bidding but it is organized once a day. Reserve holder cannot offer its part of reserve capacity to hourly market that is accepted in the yearly market. The maximum bid size is for FCR-N is 5 MW and for FCR-N 10 MW. Hourly bids for period of 24 hours must be submitted at an accuracy of 0.1 MW to Fingrid no later than 6.30 pm EET. This period is always the same as Elspot period i.e. 01:00 – 01:00 EET. From hourly markets Fingrid buys only the amount that fulfills its part of the obligation in reference to jointly maintained reserves. Each hour of the period is observed separately and the price of the hour is set by the most expensive bid accepted. Fingrid confirms the hourly transactions for the next Elspot period by 22:00 o'clock. (Fingrid 2017a; Fingrid 2017h)

Reserve volumes for maximum FCR-N and FCR-D capacity of a power plant machinery can be calculated with equation (1) and (2) correspondingly. Reserve capacity maintained by a power plant machinery is based on the current values of maximum (P_{max}), minimum power (P_{min}) and set value (P_{set}) but also reserve capacity verified by the reserve volume tests ($C_{maximum\ reserve}$).

$$C_{FCR-N} = max\left[\min\left(P_{max} - P_{set,}\, P_{set} - P_{min,}\ C_{maximum\ reserve}\right), 0\right] \tag{1}$$

$$C_{FCR-D} = max[\min(P_{max} - P_{set} \ - C_{FCR-N}, C_{maximum\ reserve}), 0]. \tag{2}$$

Reserve holder gets the capacity compensation in hourly basis based on the agreed capacity and the verified capacity. Reserve holder receives compensation on the basis of the capacity that was confirmed with measurements, however, at the most the agreed reserve volume. If the reserve holder can provide the agreed capacity fully, it receives full capacity compensation. However, if the provided hourly reserve capacity is below the agreed capacity, reserve holder is obligated to pay to Fingrid 100 per cent of the reserve price in the hour in question in compensation for the capacity not supplied. (Fingrid 2017h)

Fingrid compensates the balance error caused by FCR-N activation in the production balance or in the consumption balance. This error is referred to as reserve electricity and it is calculated with equation (3) as follows:

$$E_r = \frac{\sum R \cdot \Delta t \cdot 50\ Hz}{3600\ s} \cdot k \tag{3}$$

where, ΣR is the actual total volume of the frequency containment normal operation reserves in balance provider's balance multiplied by 10, Δt denotes the time deviation change during the hour in question and the correlation coefficient k (=0.7) takes into account the effect of dead band on the activated energy. (Fingrid 2017a)

The balance error caused by the FCR-N reserves is calculated hourly, and removed with transaction from the balance (production or consumption) of the balance responsible party (BRP) in conjunction with the balance settlement. Compensation of reserve electricity is based on the hour regulating prices as follows. In a situation with a frequency below the normal range (50 Hz), the calculated reserve electricity is compensated to the reserve holder with up-regulation price and in a situation whit the frequency above the normal range, the calculated reserve electricity is charged at the down-regulation price from the reserve holder. (Fingrid 2017a) Thus, in addition to a capacity compensation that reserve holder receives from its FCR-N capacity, reserve holder's profits are based on the electricity price of the balance error caused by the FCR-N activations.

2.4.3 Procurement of automatic frequency restoration reserves

The amount of maintained aFRR is 300 MW in Nordic level. However, it is maintained only for predefined morning and evening hours on weekdays. (Fingrid 2017d) Like frequency containment reserves for normal operation, each countries aFRR capacity obligation is proportional to annual electricity consumption. Fingrid procures its part of the obligation (70 MW) from Sweden and domestic hourly market. The aFRR market is based on bids made by operators. Bid size is 5 MW and the bid can be either for upward or downward regulation. Moreover, one bid can be composed of multiple power plant generators. Reserve operator who has an agreement with Fingrid can submit its bids for tomorrow until 5.00 pm EET. Fingrid reports the results of next day's procurement at latest 6.05 pm EET. If reserve bids have priced equally, the firstly submitted is accepted. Reserve owner gets compensation from both capacity and energy separately. Capacity compensations principle is a pay-as-bid but energy compensation depends on activation. Energy compensation is based on the imbalance price, surplus energy is compensated with the hour's up-regulation price while deficit is bought at the down-regulation price. (Fingrid 2016a; Fingrid 2016b)

The aFRR activation is done centrally from Norwegian TSO's (Statnett) control room based on their calculation of needed power for returning the frequency back to its target. Statnett sends activation signal to relevant TSOs including Fingrid. Then Fingrid sends the activation signal to reserve owners who passes the signal to the reserve unit. The direction of the activation signal (increase or decrease) stays in the same direction until the nominal frequency is reached. (Fingrid 2016a)

2.4.4 Procurement of manual frequency restoration reserves

The backbone of Nordic power system is the manual frequency restoration reserves which are used for power balancing in imbalance situations. The volume of maintained manual frequency restoration reserves in each Nordic country must be sufficient to handle the local dimensioning fault. This is simply the requirement for the minimum manual upward regulating power. Fingrid procures needed upward manual frequency restoration reserves from balancing power market, balancing capacity market and reserve power plants. These reserves are activated in the foregoing order if needed. Similarly, down regulating power must be sufficient enough because each Nordic country must be able to handle all imbalances in both direction single-handedly. (Entsoe 2016, Fingrid 2017d)

Balancing power market

In Nordics, majority of the manual activation of restoration reserves is based on the Nordic balancing power market. This Nordic-wide commercial market is available to Finnish balance responsible parties but also the market participants under their balance service agreement. Alternatively, market party can directly sign a separate balancing market agreement with Fingrid to have a right to participate in the balancing power market. This market, coordinated by Fingrid, is a part of the Nordic regulation power market. (Fingrid 2017d)

Production and load owners are allowed to submit bids to the balancing power market according to their adjustable capacity. Finnish resource owner can submit bids with following information: each regulation bids must contain information about, time (hour and date), power (MW), price (€/MWh), name of the resource. Bid needs to be at least 5 MW of power if the bid can be ordered electronically, otherwise the minimum bid size is 10 MW. Although, balance responsible party may aggregate its bids from multiple resources if aggregated capacity is under its power balance and it locates fully in same regulation zone, i.e. either in Northern or Southern Finland. Moreover it is possible to combine consumption and production in the same bid. For all bids, the time in which the capacity need to be fully applicable is 15 minutes and the chance of power need to be verified in real time. (Fingrid 2017i) Figure 9 shows the type of balancing bids.

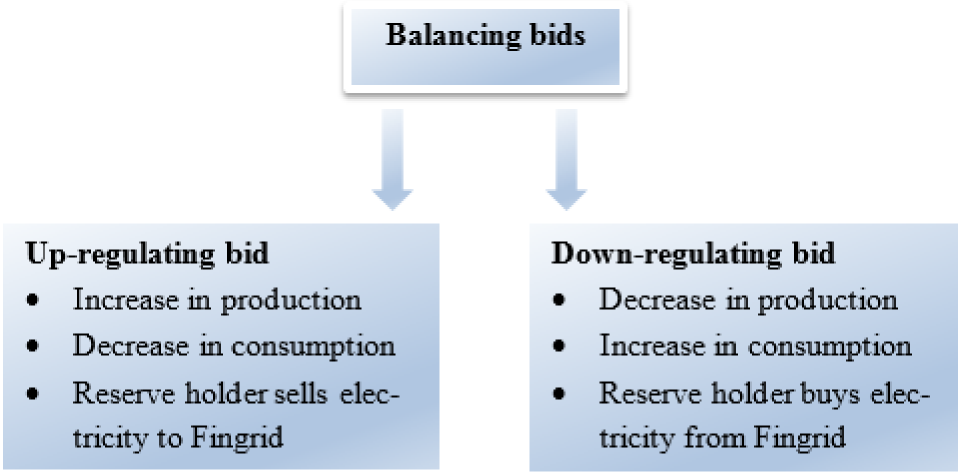

Figure 9. *Balancing power bids (Fingrid 2017c).*

Balancing bids can be submitted and changed until 45 minutes before operational hour when they become binding offers. If there is a fault in offered resource, the bid can be changed after exceeding the time limit. Fingrid delivers balancing bids of its own area to the Nordic regulation power market, in which the bids are used to form curves for both type of regulation and bids are organized based on the prices. For balance management purposes, the bids which are closest to the Spot price are accepted first. The most expensive down-regulation bid is used first in case of down-regulation and the most inexpensive up-regulation bid is used first for up-regulating. The last accepted bid of up-regulation and down-regulation defines the price of the up-regulation and down-regulation respectively. (Entsoe 2016)

When there is enough transmission capacity between bidding areas, all needed bids are accepted in price order and hence the regulation price is uniform within Nordic region. However, when there is a bottleneck situation between two price areas, TSO's determine jointly when it's no longer possible to regulate areas mutually and as consequence, balancing power market diverges. If exporting area's balancing bids cannot be used in due to a bottleneck situation, the regulation price is the price of latest activated bid before congestion occurring. Importing areas balance is restored by using the cheapest bids in the subsystem which rectify the balance. (Entsoe 2016, Fingrid 2017i)

Fingrid can use the submitted bids also for special regulation. This means that regulation is carried out for other reasons than balance handling purposes. Bids activated are not necessarily in the price order since TSO uses the bids which are suitable in terms of congestion management or other specific reasons. Special regulation can come to a question when unpredictable situations, for instance, production unit tripping occurs, bids with faster response time than 15 minutes can be given priority over the price order if necessary. These bids are activated as special regulations and they are compensated in accordance to the bid but not taken into account in the forming of the price of imbalance power. However the special regulation can be changed to balance regulation by activating skipped orders if needed, in which case the price of bid is formed according to highest accepted bid price. Otherwise, activation is compensated as pay-as bid. Moreover, special regulation is used for managing congestions caused by reduced grid capacity between price areas after day-ahead price is formed or to support other European synchronous system. (Entsoe 2016)

Balancing capacity market

Balancing capacity market was introduced as a new reserve market in spring 2016 by Fingrid. The purpose of the market is to secure sufficient amount of fast disturbance reserves during time of reserve power plant maintenance breaks and other specific needs for additional fast disturbance reserves (Fingrid 2017d). Fingrid purchases additional fast disturbance reserves from balancing capacity market with bidding contest if needed. The requirements of offered resources are consistent with the requirements of balancing power bids. The bidding competition is arranged for complete weeks based on need of fast disturbance reserves. Fingrid publishes the needed product (up- or down-regulation) with preliminary amount of power for each trading period. Reserve holders of the accepted reserves are obligated to submit balancing capacity bids to the balancing power market for next day-ahead period's hours. These bids must be submitted one day prior to the start of the next day's procurement period. The bid volume should be the same as the accepted volume but activation price can be decided by reserve holder. Balancing capacity bid activation comes into question when power system restoration requires it and there are no more balancing power bids available to be used. (Fingrid 2017j)

Accepted balancing capacity bids in balancing power market are compensated according to a bid price. This capacity compensation ensures a minimum compensation for participating in the balancing power market. Although, final compensation is determined after the procurement period based on submitted bids and reserve activations. Full compensation is paid only for hours when bid has been offered in full volume and submitted before deadline. Smaller balancing power bid means smaller capacity compensation. Activated bids are compensated based on the energy price of the bid. These activations are taken into account in compensation by subtracting the energy compensation from the capacity compensation. Thus the energy compensation does not increase the final compensation unless the energy compensation exceeds the capacity compensation. (Fingrid 2017j)

Other reserves

Reserve power plants are also one way to secure balance in the grid. These (also referred as fast-disturbance reserves) are only used in serious power deficit situations. Fingrid has own reserve power plants and leased power plants from other operators by which it can meet the requirement of manual frequency restoration reserves. Currently, Fingrid's owned reserve power plant capacity is 953 MW and the leased reserve power plant capacity is 301 MW. These capacities are not used for commercial electricity production. Requirements for the reserve power plants dedicated to this operation have strict technical and operational requirements. For instance, the entire capacity of the plant must be fully utilized in 15 minutes. These power units of these plants are subjected to testing and trial use every six weeks. Each reserve power plant must has a start-up reliability of 90 %. (Fingrid 2019a, Fingrid 2019b)

Energy Authority in Finland has a power reserve system (also referred as peak load capacity) which is separated from Fingrid's reserves. Peak-load capacity is based on the law and the authority decides both the needed amount of reserve capacity and resources, i.e. which power plants and consumption locations belong to the system. The purpose of the system is to ensure that there is enough power available in Finland during winter months (December – February). The authority asks publicly bids from the operators to fulfill the needed reserve capacity. For the time span of 1.7.2017 – 30.6.2020, Energy Authority confirmed 707 MW of reserve power by the best purchase price. Reserves were accepted from 4 power plants and two demand response capable facilities. Fingrid administer the system and decides the activation of the reserves. The reserves are only activated during the winter months (1.12. – 28.2.) if the market-based demand and production do not meet in the day-ahead market or in the balancing power market. Power plant capacity is offered to day-ahead market with its price cap (3000 €/MWh). Once the unit is running, its available capacity is offered to balancing power market at least the same price or higher if there is higher marked-based balancing power bids but maximum at the balancing power market's price cap (5000 €/MWh). The consumption capacity is offered to the balancing power market and activated only if market-based bids are not enough. The requirements of the power plants and consumption locations are strict during the winter time. Consumption flexibility must be able to be utilized in 10 minutes if needed for balancing power while the reserve power plant units must be able to start up in 12 hours. (Energy Authority 2019a; Energy Authority 2019b; Fingrid 2019b)

2.5 Market potential for hydro units

The purpose of this chapter is to give an outlook to the available market places; their volumes and price levels. The examination period is from 1.1.2018 – 30.8.2018. Data has been collected from Fingrid's open data set (Fingrid 2018d) and Nord Pool's historical market data (Nord Pool 2018c). This short examination period is sufficient to give a some kind of understanding on the market prices and volumes but it is not meant to be a comprehensive insight to the market behavior nor development.

In Finland, there are three physical energy markets in which producer can sell its energy production: day-ahead (Elspot), intraday (Elbas) and balancing power market. These markets are cleared in the same sequential order as it has presented above. Day-ahead and intraday markets volumes for Finland price area in 1.1.2018 – 30.8.2018 are presented in Figure 10.

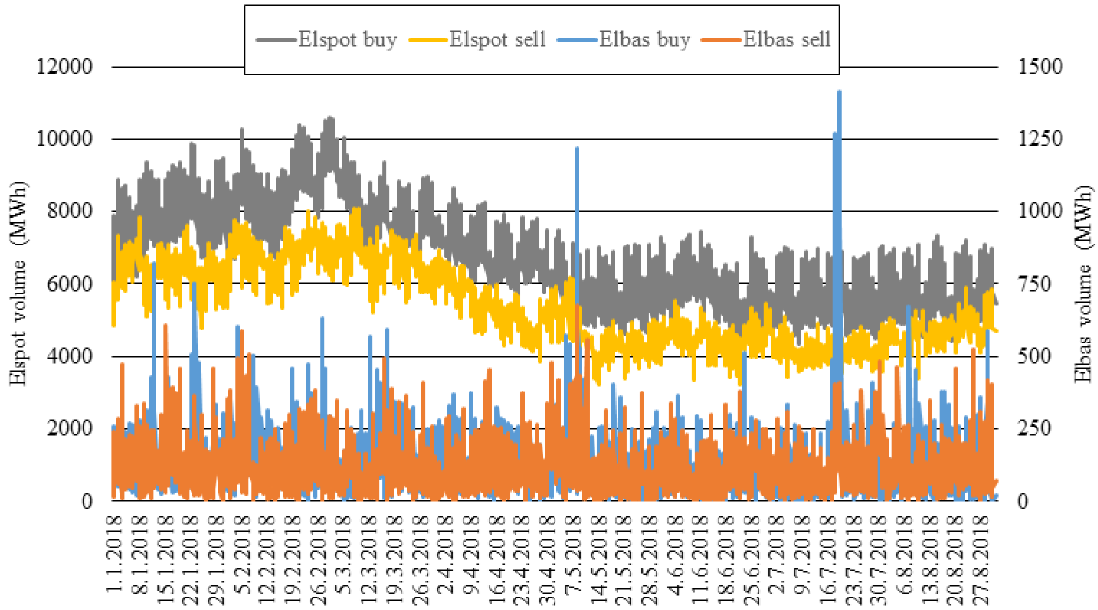

Figure 10. *Nord pool day-ahead (Elspot) and intraday (Elbas) markets hourly traded volumes in Finland 1.1.2018 – 30.8.2018. Two upmost lines denotes volumes in Elspot.*

From Figure 10, we can made multiple conclusions. Firstly, day-ahead market is more liquid than intraday market because its volumes are multiple times greater and therefore its exchange is more certain. During the studied period, hours in which Elbas trades were not performed was 0,6 % and 0,4 % for buy and sell, respectively. This might be caused by the restricted supply and demand, i.e. low volume or from unfavorable bid-ask spread. In contrast, the intraday market buy volume have been over 1000 MWh per hour in ten occasions. This emphasizes the demand volatility of the intraday market, even if the high demand was most probably aroused from unplanned events such as failures in production side.

Secondly, buy volumes are greater on average than sell volumes in both market places. Especially, in Elbas highest sell volumes are greatly lower than highest buy volumes. In the day-ahead market, greater buying than selling volume is obvious consequence of imported energy to Finland. From the intraday market perspective, buying energy from another Nordic area is not always possible due to restrictions in the transmission capacity. Table 1 presents minimum, average, maximum and total traded volume for the both intraday and day-ahead markets.

Table 1. Day-ahead (DA) and intraday (ID) market statistics in period 1.1.2018 – 30.8.2018.

	ID Buy	ID Sell	DA Buy	DA Sell
Minimum	0 MWh	0 MWh	4367 MWh	3225 MWh
Average	129 MWh	114 MWh	7011 MWh	5377 MWh
Maximum	1412 MWh	679 MWh	10605 MWh	8089 MWh
Total	751 GWh	664 GWh	40726 GWh	31236 GWh

Finally, seasonal effect on demand can be seen from Figure 10. During winter in day-ahead market, both buy and sell volumes are high until March when they start to decline. Same kind of effect is harder to see in intraday market where the demand and supply mainly arises from sharpened production and consumption forecasts.

One good gaining possibility is to utilize hydro asset's capacity through balancing power market event though its volume is lower on average than intraday market: on average up-regulation volume were 13 MWh per hour while average down-regulation volume were -21 MWh per hour during the examined time period. Figure 11 shows an illustration of price volatility of balancing power prices which is highly depended on available balancing bids. Additionally, day-ahead price volatility is presented in Figure 11 due to comparison purposes: day-ahead price is used as balancing power price if there are no either up- or down- regulations carried out in the hour in question. Based on the examined data, the down-regulation was most common in Finland price zone with 44 % share of the all examined hours. The shares of no-regulation and up-regulation were 32 % and 24 %, respectively.

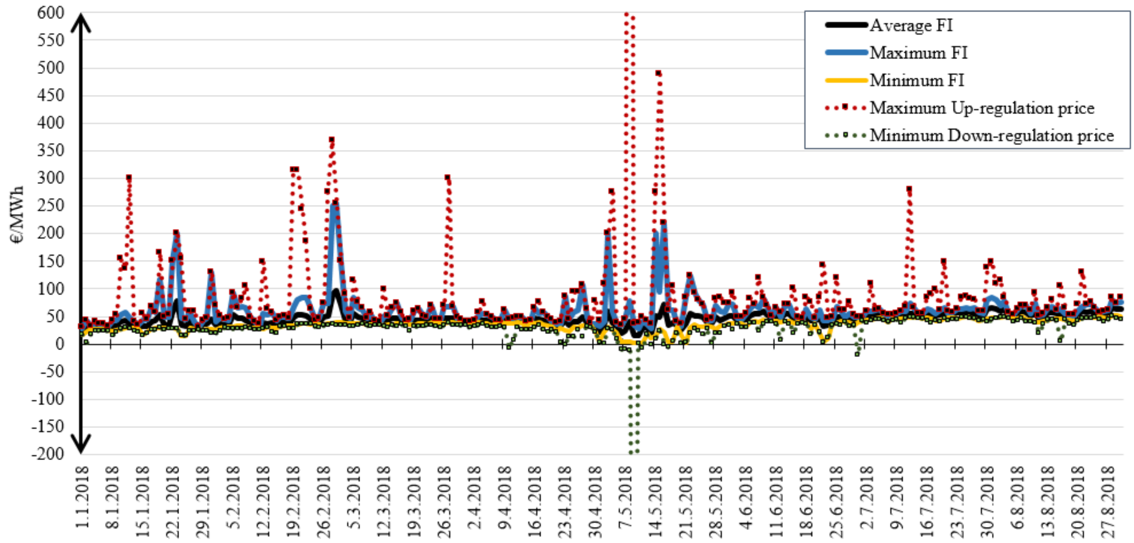

Figure 11. *Finland area balancing power and day-ahead prices as daily values in 1.1. – 13.8.2018.*

In order to have some readability to Figure 11, highest (2999 €/MWh) and lowest (-1000 €/MWh) balancing power prices of the examined period are not shown. In the hour of highest up-regulation, ordered up-regulation power in Finland was roughly 820 MW. At that hour, all available up-regulation bids in Finland were activated due to a unplanned trip of the nuclear power unit Olkiluoto 2 (Fingrid 2018c). On the other hand, down-regulation became -1000 €/MWh for two successive hours when ordered down-regulation in Finland were -218 and -414 MW. The down-regulation was needed due to high level of hydro production caused by the flooding added with higher realized wind power production than was forecasted (Fingrid 2018c). These extremely high prices were realized within short time period; high up-regulation took place at hour 17-18 CET in 8.5.2018 whereas down-regulation took place during the next day's hours 00-02 CET. Figure 14 shows the hydrological situation mentioned above.

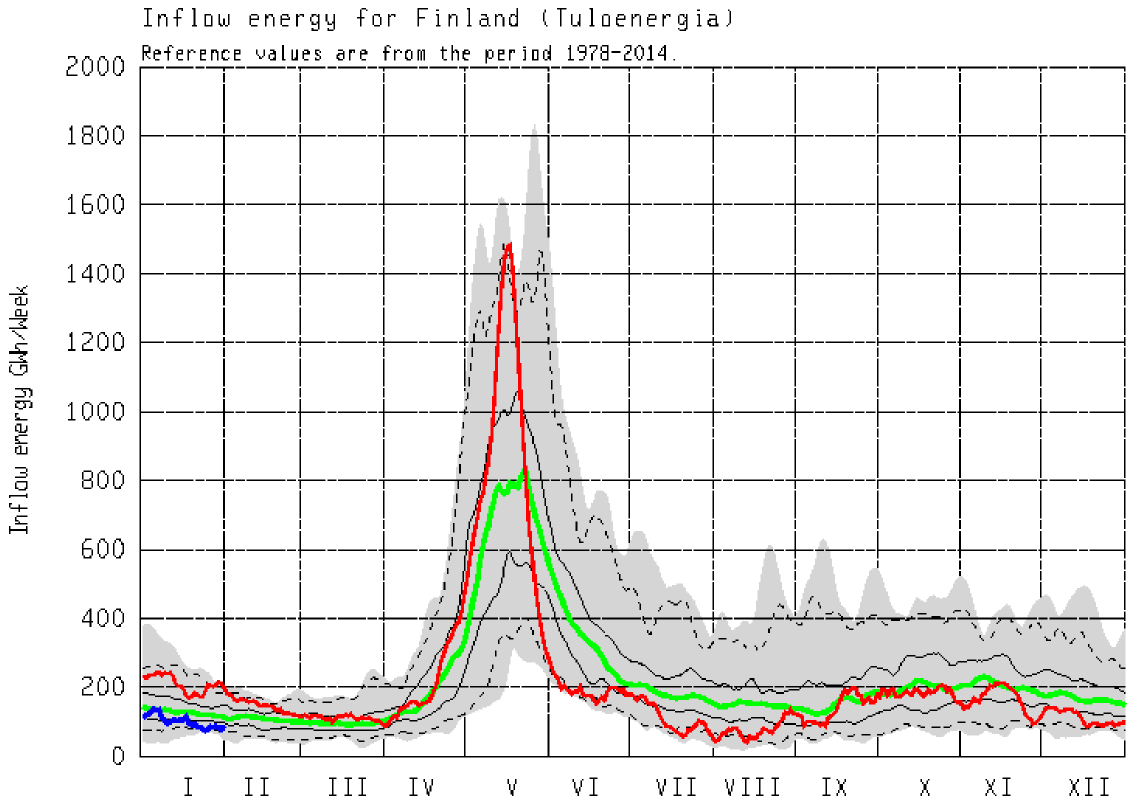

Figure 12. *Inflow energy for Finland. Blue line shows year 2019 and red line shows year 2018. Other lines and grey area are references from period 1978 – 2014: median (green line), fluctuation range as 5 % and 95 % (dashed black line), fluctuation range as 25 % and 75 % (black line) and minimum and maximum value (grey area). (Finnish Environmental Institute 2019)*

One can see from Figure 11 that the price risk for up-regulation have been greater than for down-regulation since the premium between up-regulation and day-ahead price is higher than with corresponding down-regulation. Nevertheless, during the examination period there have been almost 40 hours of negative balancing power price resulting seven days when the minimum down-regulation price have been negative. Moreover, during the day's day-ahead price-peaks, the risk for relatively low down-regulation are possible. For instance, in 23.1.2018 at hour 11-12 CET, Finland area price was 121,04 €/MWh but balancing power price became 34,30 €/MWh with down-regulation of -48 MW. To clarify that day's price level, maximum, average and minimum day-ahead prices were 200,02 €/MW, 78,54 €/MW and 28,11 €/MW, respectively. From producer's point of view, it is obviously beneficial to produce according to plan in hours when the day-ahead price is high and the hour's down-regulation price is low.

Even though power reserves are not considered to the same extent than intraday energy trading in this thesis, they can create good value creating possibilities to hydro units. Next there are two Figures about Fingrid's hourly FCR market. The first (Fig. 13) concerns disturbance reserves while the second (Fig. 14) shows frequency containment reserves for normal operation.

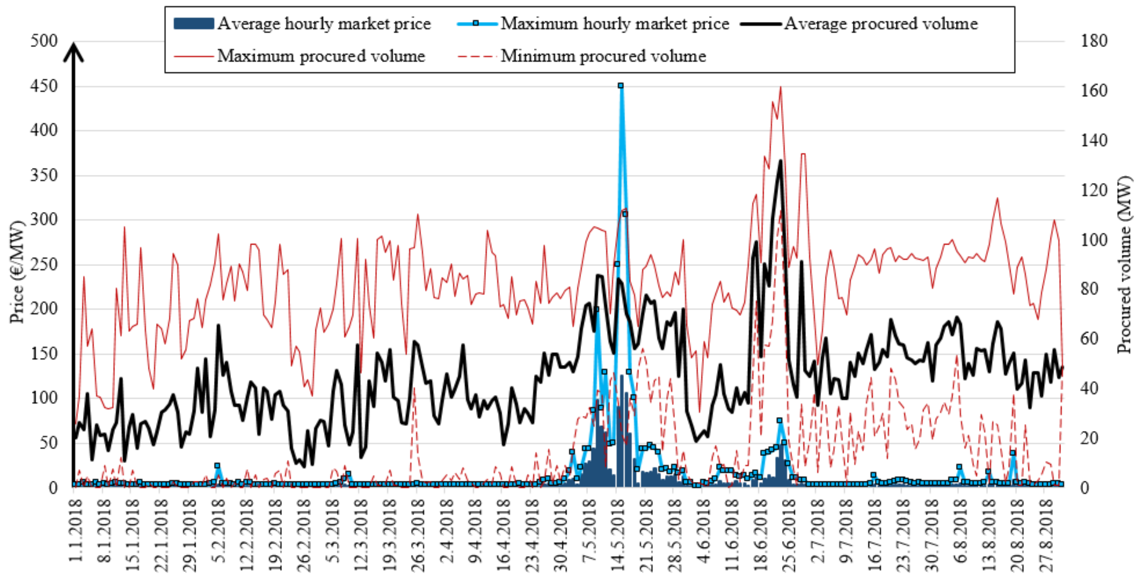

Figure 13. *Hourly FCR-D procurement in 1.1.2018 – 31.8.2018.*

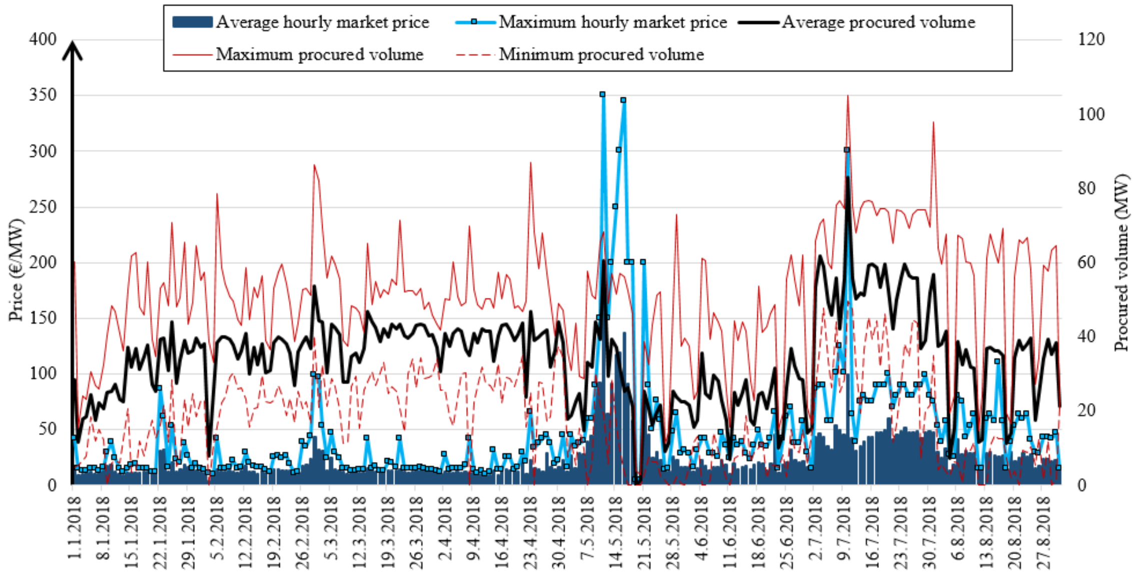

Figure 14. *Hourly FCR-N procurement in 1.1.2018 – 31.8.2018.*

From Figures 13 and 14 can be seen that the procurement of FCR-N has been more stable, i.e. there are not as much zero volume hours in the procurement than with the FCR-D. In addition, price of the FCR-N procurement have been on average higher than with FCR-D. As can be seen from the figures, there is volatility in procurement volume and price in both type of reserves. This is due to the fact that Fingrid uses hourly markets only to the extent that is needed. Thus, the hourly market procurement varies hourly based on the availability of other FCR procurement channels such as yearly market reserves which hourly availability is based on the reserve providers free capacity but is at most the agreed procurement volume (Fingrid 2018a). Reserve procurement from the yearly market have been varying in past years. For instance, in year 2018 (2017), Fingrid procured 72,6 MW (55 MW) and of normal operation reserves and 435 MW (455,7 MW) of disturbance reserves (Fingrid 2018a). In the yearly market the reserve price is constant during the entire calendar year. The yearly market volumes and prices from recent years added with some of the hourly market's procurement key figures from the studied period are presented in Table 2.

Table 2. *Domestic reserve markets. Hourly market data is from the studied period.*

	Yearly market		Hourly market		
	2018	**2017**	**Minimum**	**Average**	**Maximum**
FCR-N price (€/MW,h)	14,00	13,00	0,00	24,64	350,00
FCR-N volume (MW)	55,00	72,60	0,00	34,49	105,00
FCR-D price (€/MW,h)	2,80	4,70	0,00	7,12	450,00
FCR-D volume (MW)	455,70	435,00	0,00	44,61	162,00

Maximum hourly prices of the examined period that Table 2 shows, were realized in May when the maximum day-ahead price was also high (see Fig.12). Moreover, during that time, inflow to hydro reservoirs was relatively high in Finland and therefore there could have been less hydro units' reserve capacity available which in turn may have raised the reserves' prices. This high inflow is illustrated with red line in Figure 12.

Basically from hydro production perspective, FCR-N has greater influence to the hydro unit operation than the FCR-D since the FCR-N is activated almost constantly and these reserves alter hydro plant's production in both directions. Whereas, FCR-D is activated not as often and only for production increase.

Since FCR-N could have more severe impact on the hydro unit production; its efficiency and wear and tear of a turbine, hydro plant's FCR-N capacity might be associated with higher price than FCR-D capacity. On the other hand, in hydro production planning, the question is also about production allocation: once a hydro unit is obligated to provide reserves it decreases attendance to other available markets. Hence when sales of reserve capacity leads to loss of revenue in the energy market such as day-ahead market, the opportunity cost of water should be considered. A drawback in Figures 13 and 14 is the lack of comparison between day-ahead price and reserve prices. According to a master thesis (Kongelf & Overrein 2017) that examined, among other things, frequency containment reserve market in Norway in a certain time period, the reserve prices were high during night when day-ahead price is low and generally reserve prices falls during the rest of the day while day-ahead price reaches its maximum. Basically, hydro unit cannot provide FCR if it is running at its minimum power output and therefore it requires hydro producer to produce more energy to be able produce FCR-N. The issue of capacity allocation will be discussed shortly later in the chapters 3.3.3 and 5.

3. HYDROPOWER

Hydropower production differs from any other electricity production by nature as its variable cost are low and the output can be scheduled to most profitable hours because water can be stored in reservoirs for later use. However all hydropower plants have their own working environment and features that have to be known in order to make most of it.

This chapter gives an outlook of hydropower producers (denoted from here to throughout the thesis simply as hydro producer) activities. At first, the fundamentals of hydropower production and hydrologic environment are introduced. Then the chapter continuous with presentation of a hydropower planning and decision making with concentrating on intraday activities.

3.1 Hydropower stations

Cost-effective and environmentally friendly hydropower has a crucial role in power supply across the world. It covers at least half of the electricity consumption in more than 35 countries and approximately 16 percent of the global electricity consumption (IRENA 2015). Hydro plants requires a remarkable monetary investment in the beginning but the operation costs are low due to a high level of automation, free fuel and low maintenance costs. Flexible, rapidly adjustable power output make hydropower units ideal for balancing of power balance. Electricity production can be adjusted fast by only changing the amount of water released through the hydroelectric power unit. (IRENA 2015, Vattenfall 2017).

Hydropower is based on well-known and mature technology. Hydropower has provided power in Finland since the late of 19th century when first plants were built to meet electricity demand of growing industry. From those days production has increased: at the beginning, hydropower production increased by harvesting new rivers and later most of production increase has been based on upgrading existed plants. Today, all economically feasible rivers are either harvested or protected by law. Due those reasons, upgrading have been most common way to increase hydropower production in Finland. Upgrading of existed plants is efficient way to increase power output because it can be done economically in pursuance of old machinery renovation. Power increase can be done by upgrading of the power of existed machinery that has come to an end of life cycle or constructing new units within a hydropower plant. (Kemijoki Oy 2017; Energiateollisuus 2005; IEA-ETSAP 2015) Production capacity is one of the key factors when considering hydro plant’s flexibility from reserve and energy markets perspective.

3.1.1 Electricity generation

Hydropower unit generates electricity in a fairly simple way. The basis is in a height difference between upper and lower water level of the hydropower plant which is created with the help of a dam. The height difference is called a head. Water stored in the higher height level (reservoir) has a potential energy that is converted to a kinetic energy when the stored water is discharged through intake into the penstock, and finally before reaching lower elevation, pass the turbine. The flowing water (kinetic energy) spins the turbine and thus the energy is transferred into mechanical energy. Then the rotation of the turbine enables electricity production of the generator which in turn feeds the produced power through the transformer into the power grid. (IRENA 2015, Vattenfall 2017). In Figure 15 is presented a principled graphical representation of hydroelectric station.

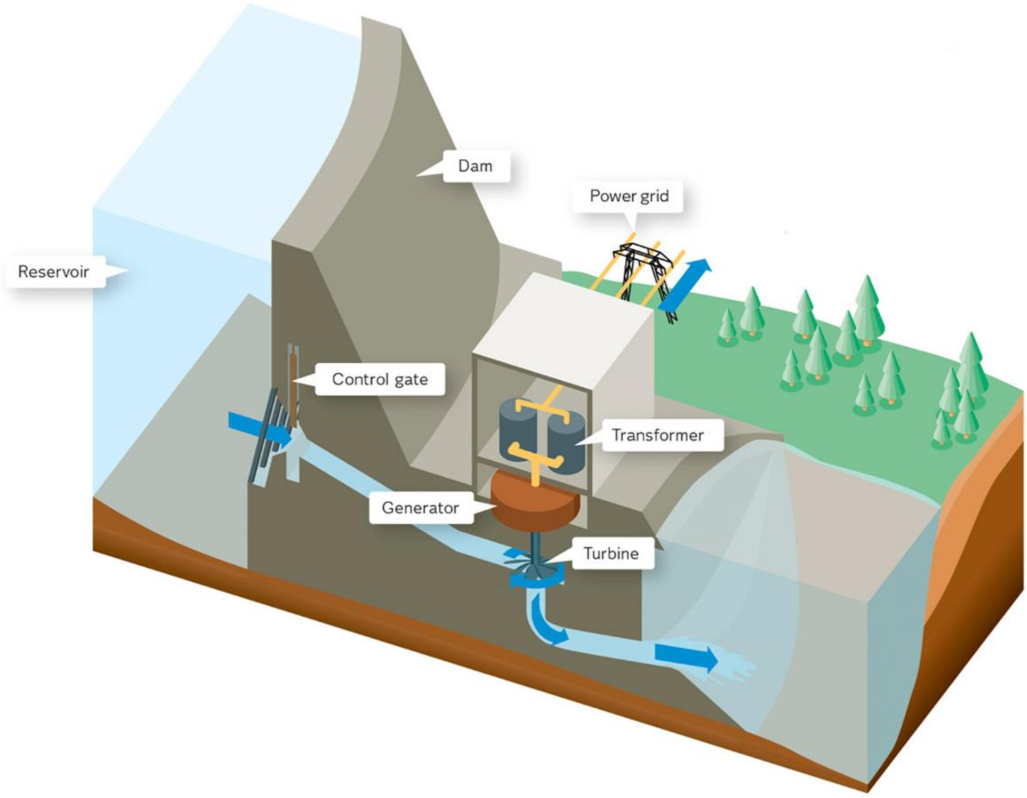

Figure 15. *A generic hydropower plant scheme (Vattenfall 2017).*

In certain circumstances, water is spilled past the stations through a spillway (not shown in Figure 15). This is highly avoidable situation in the eyes of hydro producers since the potential energy of the spilled water is lost. So basically spilling is done only when it is necessary in order to control water level of the reservoir. The most usual case for spillage occurring is heavier inflow than discharge capacity of the turbine(s) because the reservoir will eventually be filled up of water. In Nordics these cases are particularly during the spring when snow melts and autumn when precipitation increases. Also maintenances may cause need for spillage, but often it can be avoided. In most cases, maintenance work can be planned beforehand and therefore scheduled to be done during a period when inflow can be either stored to a reservoir or discharged through other turbines of the station if possible. (Crona 2012) However, it might be profitable to lose the potential energy of water by spilling when producer gain exceptional prices from balance power or reserve markets.

The amount of generated power depends on used potential energy, and therefore generated electricity can be presented as a function of discharge and height of the head. This will be clarified with following equations. In the beginning, stored water have potential energy U (J) which can be presented by function:

$$U = mgh, \tag{4}$$

Where m is the water mass (kg), g is the local gravitational acceleration of the Earth (m/s^2) and h is the head of the plant (m). From this equation, can be seen that potential energy is linearly depended on the head and the mass of the water. Water mass can be presented as multiplication between density ρ (kg/m^3) and volume V (m^3):

$$m = \rho V, \tag{5}$$

Theoretical power P_{th} (J/s) is the potential energy transferred per time unit t (s):

$$P_{th} = U/t. \tag{6}$$

With the equations (4) and (5) the theoretical power equation (6) can be presented as follows:

$$P_{th} = \rho Vgh/t. \tag{7}$$

The volume of water over time can actually be written as the discharge Q (m^3/s) through the power plant. In addition, the head of the hydro plant is subtraction between intake and tail water level. By these modification of format the previous equation (7) is simplified to a form:

$$P_{th} = \rho gQ(h_{intake\ water} - h_{tail\ water}) \tag{8}$$

Like any other energy production method, hydropower cannot utilize its potential energy fully. Therefore the actual power P must be scaled with an efficiency factor η which takes the losses during the energy conversation into account:

$$P = \eta\rho gQ(h_{intake\ water} - h_{tail\ water}) \tag{9}$$

An actual hydro plant lose 12-14 % of the water's total potential energy while it produce electricity. Most of the losses (11-12 %) comes from water flowing through waterways and past the turbine. Firstly, the flowing water mass encounter friction in the penstock. Secondly, there are losses caused by turbine that depends on turbine type. Final losses from water discharge comes from the losses caused by tail water: how water is transported away from the turbine, allowing new water to enter. Minor part of the losses (2 %) comes from electricity generation and transfer with generators and systems. (Finn R. Førsund 2007).

In conclusion, the power of a hydro plant depends on the head of the plant, the discharge through a turbine and the efficiency of energy conversion. Production can be adjusted simply by changing water discharge through a turbine. However, water discharging through a dam will eventually decrease the head of the plant by changing intake and tail water level, and thus lead to a decrease of the power output. The decrease of reservoir level occurs when the discharging is greater than the inflow. On the other hand, river usually resist the flow caused by the discharge and spillage, and in situations when one of them is high, the tail water tends to increase. (Finn R. Førsund 2007; Vilkko 1999)

In many cases, hydropower plant consists more than one turbine. It is advisable to run the generators on the optimal production zone and high intake water levels because the energy per volume of water is the highest. This can be seen from an example of a combined production curve shown in Figure 16.

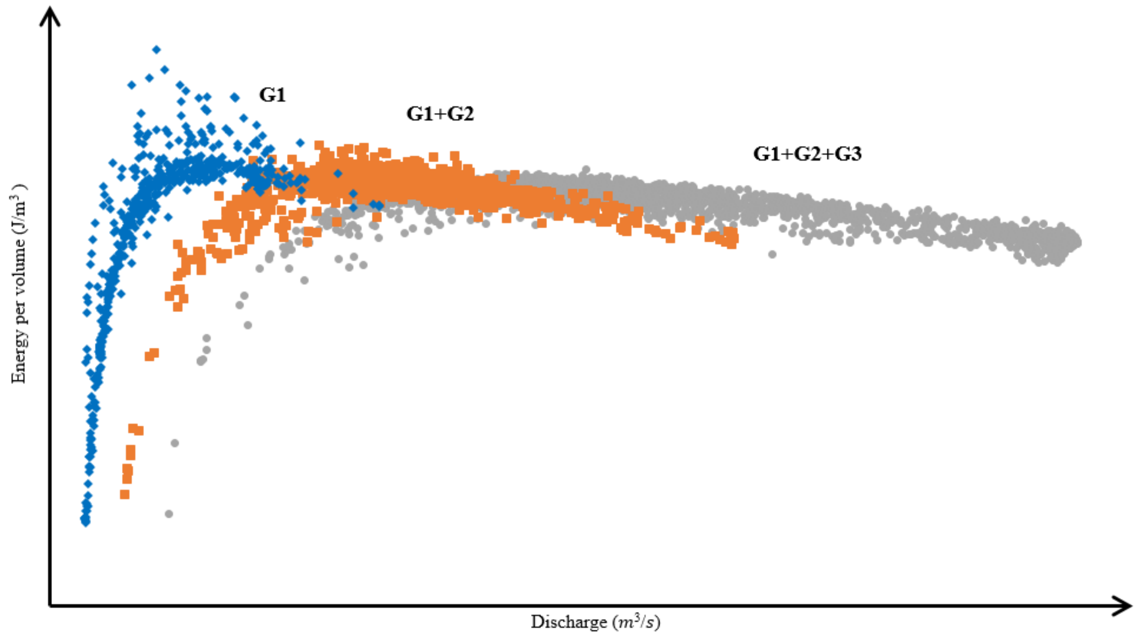

Figure 16. *Three generators combined production curve as a function of discharge according to statistical data.*

3.1.2 Hydropower plant types

Water storage capacity is used in hydropower classification. There are two basic configurations of hydropower plants based on reservoir: dams with reservoir and run-of-river (ROR) plants, without reservoir. Hydropower plants are also divided into different power sizes based on their rated power output. The hydropower plants less than 1 MW are called as micro-scale hydropower, plants in the 1-10 MW are called as small-scale hydropower and plants over 10 MW is defined as large hydropower. (IEA-ETSAP 2015)

By strictly definition, run-of-river plants have no water storage. This means that production is based on the timing and the river flow since all water must pass through the plant. Because all of the river flow is passed through the station at every turn, these type of plants maintain river as close to a natural state as possible. Thus ROR plants are environmentally friendlier than dams with reservoir which can regulate the river flow significantly. These type of plants are used in small-scale hydropower and rivers where the natural flow are not allowed to alternate due to environmental regulations. (IEA-ETSAP 2015) ROR plants are operated as base production and therefore the main driver of production plan is inflow rather than electricity price forecast. Although it is noteworthy that in many countries, definition "ROR" is used with hydro plants that have very short-term water storage capacity. This small reservoir allows water storage for hours to several days. (IRENA 2013)

Dams with reservoir, called also conventional plants, are more suitable for power regulation than ROR plants (with no reservoir) because of the water storage. Conventional plants can be subdivided into small dams with night-and-day regulation, large dams with seasonal storage (i.e. weeks to several years) and pumped storage reversible plants for energy storage and day-and-night regulating according to variety of electricity demand. Conventional hydropower offer flexibility for the power system in two ways. First of all, seasonal reservoirs can be used to storage energy to periods when the demand is higher. The inflow of a spring flood can be stored to be used in winter when the electricity demand is higher. In addition, reservoir levels might be allowed to increase during a great deal of wind power production for a time when there is no wind. Secondly, dams with reservoirs are the most flexible power production available. Those are also suitable in shorter time period's power balancing in a cost-effective way because the turbines operates with good efficiency even at partial loads and the power output can be effortlessly ramped up and down rapidly. (IRENA 2013; World Energy Council 2016)

Pumped-storage hydropower plants, like any other convention hydropower, have a capability store water in a reservoir above and therefore provide power balancing services. Although, they are a notably different as water can be pumped from the lower lever to the higher level. Both pumping water and electricity generation is done with one reversible Francis device which enables over 80 % efficiency for pumped hydropower. Water is pumped to a reservoir when electricity demand is low and then used to provide peak-load supply, so a pumped-storage hydro units provide an arbitrage between periods of low and high electricity prices. The nature of pumped hydro can be described as a zero sum electricity producer but there might although be a natural inflow to a upper reservoir which increases generation available. (IRENA 2015; World Energy Council 2016)

3.2 Hydrologic environment

Water, in every states of matter, cycles continuously on earth. In this process, called either water or hydrologic cycle, water continuously moves between earth's surface and the atmosphere. This movement is powered by solar energy and gravitation.

Hydrological cycle is a global, continuous process that can be explained with water flowing between different reservoirs like oceans, lakes, land surface and atmosphere. In this process, shown in Figure 17, a liquid state water is evaporated from reservoirs to the atmosphere. Sun heats the earth's surface and causes water evaporation, in which water changes from liquid into vapor. Evaporated water is then raised to the atmosphere with warmed thus lightened air. In the atmosphere, vaporized water is cooled down and condensation occur. In condensation, water starts forming small drops of water. A group of drops, also known as a cloud, is transported by wind. Those droplets collide with one another and therefore bigger droplets are formed. Eventually, because of gravitation, droplets gets too heavy and they fall back to the earth's surface in some form of precipitation (snow, water etc.). When precipitation hits the land, part of water infiltrates into ground in proportion to saturation of the ground while the rest flows across the surface back to the reservoir. Absorbed water can be evaporated directly from the soil surface or it can be transpired by plants. Although the water cycle is continuous process, the residence time for water varies a lot depending on precipitation and storing reservoir. (Ghosh & Desai 2006)

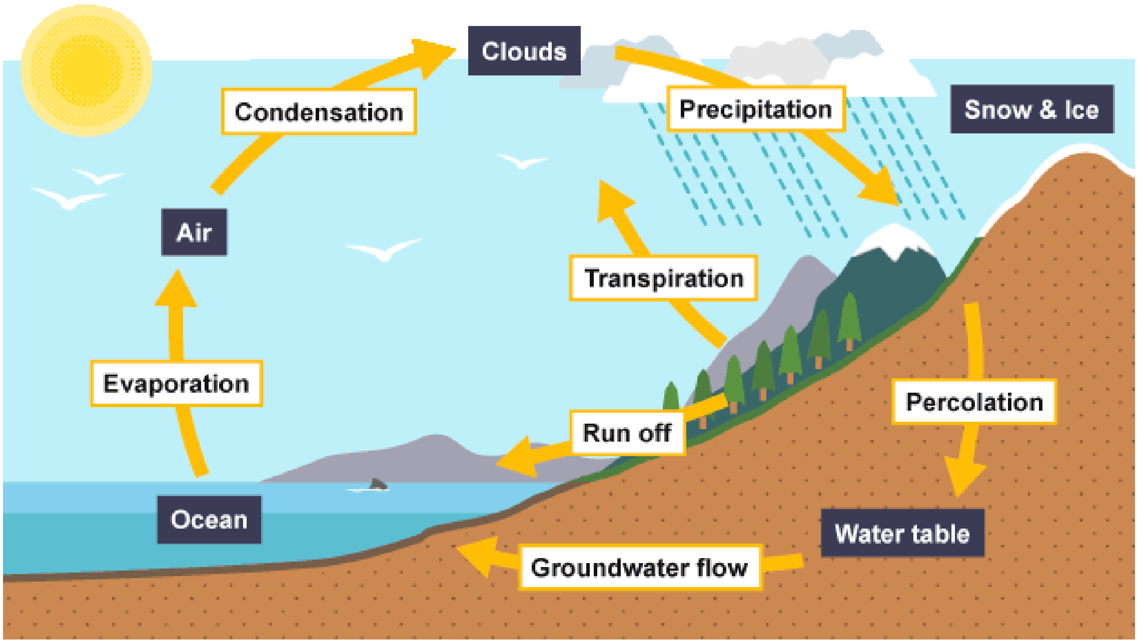

Figure 17. *Hydrologic cycle (BBC 2017).*

Hydropower use surface run off to utilize kinetic energy of water in renewable energy production. From hydropower point of view, it’s crucial to know how large volume flows through a river in each time. This flow is highly depended on catchment area of river which is the area that gathers flowing water in the river. The gathered water will eventually run through the river and thus arrive in hydropower plant as an inflow.

3.2.1 Reservoir and water inflow

In Finland, over 300 lakes or reservoirs are affected by regulation of watercourse. Regulation of watercourses means altering discharging through water structures in order to meet the targets of water resource management. There are numerous objectives for regulation. The most common objective for regulation is hydropower production but also flood mitigation is in many cases a very important objective. In addition, there are other objectives, such as water supply, navigation, recreation, fish farming and water protection or drainage. (Finnish Environmental Institute 2017a)

Each watercourse regulation project have its own permit subject to Water Act. This permit defines limits for the water levels of reservoir and in many cases sets limitations for discharging through water structures. (Finnish Environmental Institute 2017a) In the permit, allowed water level fluctuations are presented as certain water levels on specific dates. For instance, these regulation water limits often have a mandatory draw-down before flooding caused by melting snow in order to make room for heavy inflow. The calendar-based draw-down, which usually is done during late winter or early spring, might not be suitable for regulation purposes in the future when snow melting decreases and flooding occurs earlier than have expected in the current permits. (Veijalainen et al. 2017)

As can be seen from Figure 18, heavy inflow of flooding in the springtime is used to fulfill reservoirs drained during winter when the inflow is low but the electricity demand is normally highest. For these reasons, the storing capacity needed during snowmelt is formed somewhat naturally.

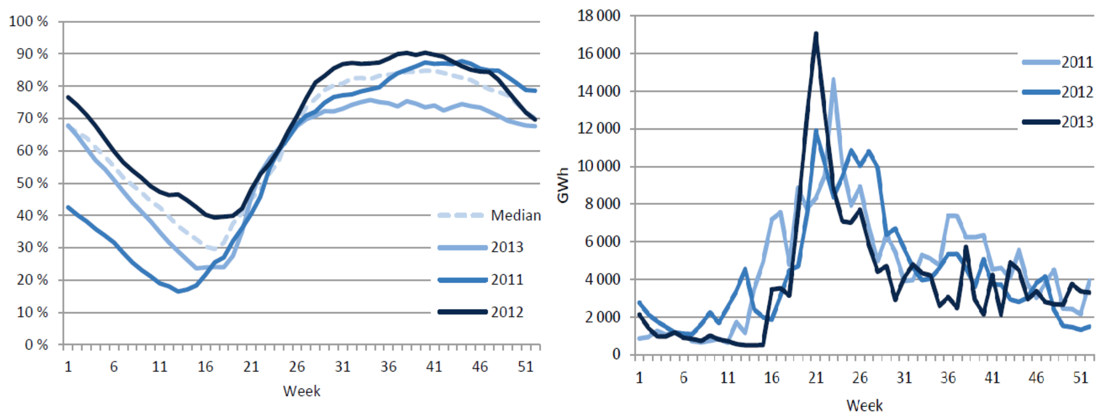

Figure 18. *Connection between effective inflow to the reservoirs (right-hand side) and reservoir levels (left side) in the Nordics (Nordic Energy Regulators 2014).*

During summer, hydro producers usually keep the water levels high or even let them raise in order to use water later when the demand is higher. Although there might be a need for save some of the reservoir capacity to deal with flash floods caused by prolonged rainfall. (Keto 2017) When flood fills up a reservoir, there might be a need for spilling water if a water inflow exceeds discharge capacity of hydro plant's turbine(s) and a reservoir is full.

A large reservoir which is filled during flooding once or twice a year is called a seasonal reservoir. Another type of reservoir relating to hydropower is a plant reservoir which is considerably smaller than seasonal reservoir. (Vilkko 1999) As mentioned earlier, reservoir water levels are regulated by legislation and permit holders, such as hydro producers, are obligated to take these limitations into account when operating hydropower. (Finnish Environmental Institute 2017a) In hydropower operation, i.e. production planning and flood risk management it is crucial to have accurate information on hydrological situation and proper hydrological forecasts. In Finland, Finnish Environmental Institute provides real time hydrological situation and hydrological forecasts for daily basis over 500 discharge and water level points (Finnish Environmental Institute 2017b). These forecasts can be used as basic data for hydro production planning along with forecasts of future energy prices.

3.2.2 Water availability

Hydro producer need to know how much water is available, and when it is available in order to schedule production in a realizable way. This is emphasized when there are several ROR hydropower plants located on the same riverbed as a chain, i.e. hydropower plants are hydraulically coupled to each other. Water released from previous reservoir arrives in the subsequent plant as an inflow after a delay. This delay depends on the distance between two cascade plants but moreover it's a question of how a certain wave travels along the riverbed (Vilkko 1999). There are different methods to model the delay between two cascaded hydro plants.

The most common way to represent water delay time is to assume that the delay time is constant. This means that the whole amount of water released at the previous plant would be available in the subsequent plant after time step or delay. With constant delay, the mathematical formulation of water balance for hydro plant (i) is presented as follow:

$$V_i^t + (Q_i^t + S_i^t) - \sum_{j \in M_i} \left(Q_j^{t-\tau_{ij}} + S_j^{t-\tau_{ij}} \right) = V_i^{t-1} + I_i^t \qquad (10)$$

,where

V_i^t is storage of hydro plant i at the end of time step t

Q_i^t is turbine outflow of hydro plant i at time step t

S_i^t is spillage of hydro plant i at time step t

M_i is set of hydro plants immediately upstream hydro plant i

τ_{ij} is water delay between upstream hydro plant j and downstream hydro plant i

I_i^t is natural inflow to hydro plant i at time step t. (Souza 2012)

In reality, this common approach is not accurate because of the streamflow routing which is the term that is used to describe the behavior of a wave travelling along a well-defined open channel. As a consequence of the stream flow routing, water is modelled to arrive in subsequent plant in steps during time period. This is demonstrated in Figure 19. (Souza 2012)

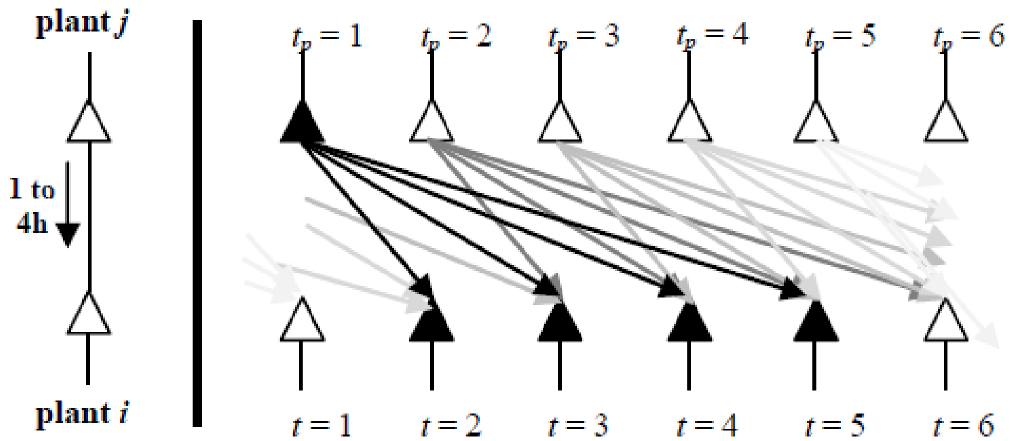

Figure 19. *Streamflow routing effect between hydro plants. The arrows present portions of moving water in river (Souza 2012).*

Figure 19 shows that, the water released from the previous hydro plant at some hour (t_p) arrives in the downstream plant from time steps (t_p+1) to (t_p+4). This approach leads to a so called streamflow routing curve, which gives the cumulative percentages of the water released from the previous hydro plant at the time step (t_p) that reach the downstream plant up to each modelled time step ($t = t + k$) until the whole amount have arrived. The k varies from the time of the first portion reaching the downstream plant to the maximum time where the cumulated arriving is 100 %. In this situation, the water balance is given by:

$$V_i^t + (Q_i^t + S_i^t) - \sum_{j \in M_i} \sum_{k=0}^{\tau_{ij}^t} K_{ij,k}^t \left(Q_j^{t-k} + S_j^{t-k}\right) = V_i^{t-1} + I_i^t, \qquad (11)$$

where factor $K_{ij,k}^t$ is fraction of water released by upstream plant (j) at previous time step $t_p = t - k$ that reach the downstream plant (i) at time step t. (Souza 2012)

Regardless of the used method, the delays need to be known precisely enough to perform well in hydropower production scheduling. This becomes more critical with nearly run-of-the-river plants which operation is strongly depended on the arriving inflow from the upstream plant (Souza 2012).

Hydro producers have natural interest of reservoir levels and hence those are monitored continuously. Monitoring is crucial since reservoir levels need to be kept in boundaries given by permit without violating other permit conditions. Because hydro producer measures plant's reservoir level and outflow in real time, it is possible to estimate the inflow into the reservoir if the total volume of reservoir is known. This volume have an influence to reservoir levels' rate of change. Basically, reservoir with smaller storage capacity reacts more rapidly to the difference in inflow and outflow than bigger reservoir.

Moreover, the rate of change might depend on current reservoir level because reservoir's volume does not necessarily increase linearly with respect to reservoir level. This is the case of an example hydropower plant reservoir illustrated in Figure 20.

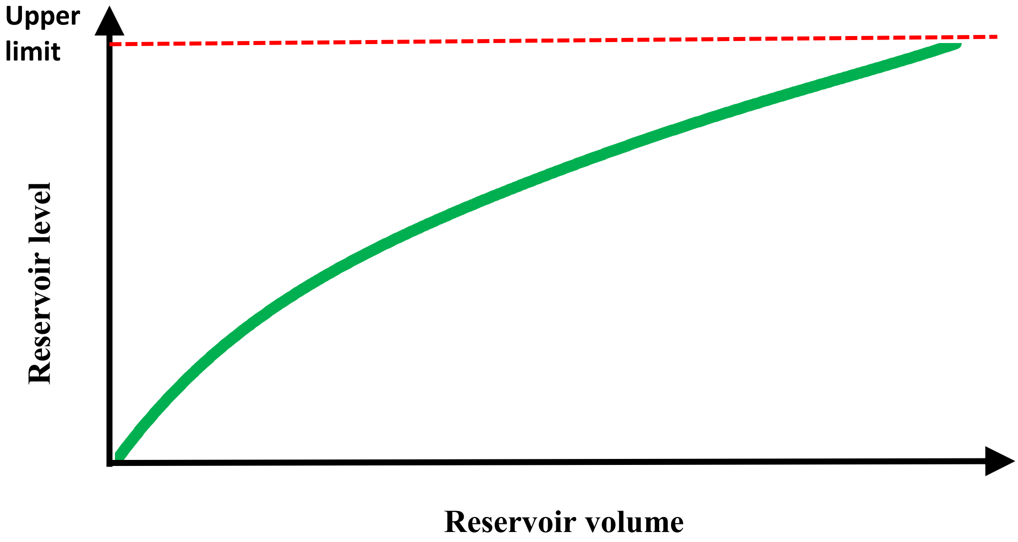

Figure 20. *Plant's reservoir's storage capacity in relation to reservoir level.*

Conclusion with the example plant's reservoir is that reservoir's filling speed is faster when it has been emptied than when reservoir is nearly full. When producer knows how reservoir level chance in relation to difference between inflow and outflow the actual inflow can be estimated. This can be useful method in inflow estimation with reservoirs that faces remarkable natural inflow which can vary relatively rapidly.

3.3 Hydropower production planning

In a liberalized electricity markets, power sellers try to maximize their profit with the assets they have. Every type of assets have their own production costs which determines the price in which production can be offered to the market. However, the marginal cost of hydro production doesn't reflect its variable costs because hydropower have no fuel costs and the operating costs are very low regardless of production level (Kauppi 2009).

From hydropower planning point of view, water is considered a scarce resource and therefore the marginal cost arise simply from opportunity cost of losing the opportunity sell the same energy later in the future. (Kauppi 2009) A simplified presentation of water value is shown in Figure 21.

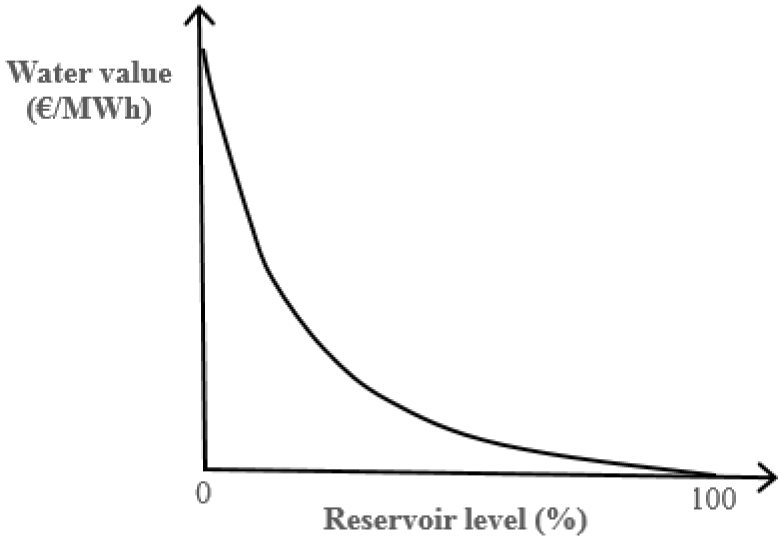

Figure 21. *Water value of a reservoir.*

From the figure, it can be seen that the water value is generally low when the reservoir is full and high when the reservoir level is low. However, the reservoir content and water value cannot be presented as simplified as Figure 21 illustrates. In reality, the inflow to the reservoir should be noticed. Thus, for a given reservoir level, the water value is higher during low inflow period than time of high inflow period (Gebrekiros et al. 2013).

To summarize, the premise of hydropower planning is to maximize the value of stored water by determining when available power is most profitable to produce. Hydro producer makes decisions about scheduled generation based on the expected future electricity price, natural water inflow and parameters of the hydro assets. (Lave & Perekhodtsev 2006) In addition to selling hydro production in electricity markets, hydro producer need to consider other markets which can be profitable especially with flexible hydro plants.

Besides hydro plant flexibility, two most crucial factors of hydro assets profit maximization are inflow and forecasted market price which both have seasonal and yearly variations. Due to electricity price hourly variations, hydro plant's flexibility is in key role when considering its profitability.

3.3.1 Flexibility of hydropower

In economically efficient electricity markets, all parties can be seen as price takers because there are enough players dealing with the markets (Fosso 1999). Thus hydro production planning aims to provide power when its most profitable. However, hydro assets have different features that constraints flexibility of production. Flexibility is highly depended on hydropower discharge capacity, hydrological coupling, environmental constraints and reservoir which all affect each other. In addition to these factors that are related to a hydro plant, there are also organizational factors that might have effect on the flexibility. (Crona 2012) The more flexible hydro asset and its water permits are, the more profitable way water can be allocated. If there is flexibility, it can be used in both energy and reserve markets because the hydro unit features and environmental constraints are same regardless of market place.

If a hydro plant has no reservoir, its output cannot be scheduled to meet the most profitable hours. Hence, only production allocation available for this kind of plant is down-regulation by spilling water. Contrary to that, hydro plant with large enough reservoir compared to its average inflow can store variations in inflow and use the water when it is more profitable. According to study of hydropower flexibility (Crona 2012), the discharge capacity combined with a reservoir size influences strongly to hydro plant's overall flexibility. If the reservoir has no significant capacity to store water, plant's discharge must be the average inflow in order to prevent spillage. Similarly flexibility is limited with plants where the discharge capacity is close to the average inflow because these plants are forced to produce electricity close to its discharge capacity during a large part of time. So as a consequence, a reservoir creates ability to change production rate since discharging doesn't have to be same as inflow to the reservoir. However, when discharging is altered, also a reservoir level and the inflow to the reservoir need to be considered (Vilkko 1999). The changed discharge must not lead to violating of the environmental permit, which defines conditions for operating of the plant by for example setting boundaries for water levels influenced by the hydro plant or altering of the hydro plant's discharge. Moreover the change in the discharging, should not lead to a situation where plant's flexibility is disadvantageously reduced in the future due to a lack of discharge capacity or low available inflow.

Typically, there are several hydropower plants located on the same riverbed. Those are hydrologically coupled to each other. This coupling is stronger when plants lie close to each other and have only a small reservoir above. When plants are hydrologically coupled, plants cannot be planned individually. For instance, if the upstream plant, which usually has the largest reservoir above, is regulated without concern of downstream plants it might lead to a situation where the downstream plant is forced to spill water in order to be able maintain allowed reservoir levels. (Crona 2012; Vilkko 1999) There is however also possibility to increase production flexibility by running the whole reach as one entity. An example of such operation is to first increase discharging of the upstream plant to ensure that the subsequent plant is operated at optimal head during the time of higher production. Alternatively, the production of a subsequent plant could be first ramped up in order to make some room available in its reservoir for the upstream plant's discharging during hours of higher price. (Crona 2012)

There are also seasonal and temporary conditions that might set some limitation to the flexibility. First of all, if reservoirs are full and inflow is high there are no flexibility left. This is usually the case during floods caused by snow melting or heavy rain. Secondly, ice related issues sets constraints how hydro plant can be regulated during winter. If a river in question is wished to form ice layer, it is important to limit the discharge during the time when it's enough cold. Afterwards, when the ice layer is formed, too big changes in regulation might break the ice layer and cause problems for operation. (Crona 2012)

The maximum flexibility that can be achieved is related to those previously presented hydro plant related factors. The actual amount of the flexibility that is utilized is depended on the organizational factors such as safety margins, resources and personnel experience. Firstly, safety margins are used in planning and operating hydro plants for different reasons. One reason is to avoid breaking environmental limits. Another reason is to avoid situations of energy imbalances. This especially relates to small-sized reservoirs which are more sensitive to forecast errors or other deviations. Considering a case where the reservoir capacity is fully used and all power is sold; any deviation from planned condition would lead to situations with energy imbalances. Therefore, as a consequence the full available energy of the reservoir is rarely used for short time regulation purposes. Secondly, the personnel's knowledge of the hydro system is a key factor affecting how plants can be operated. In complex river systems, the optimization from the planning tools might have to be complemented with human knowhow regarding how the system will behave. In case of higher degree of short time regulation, the previously mentioned safety margins might have to be shrunk and in those circumstances it is highly important that all people know what actions can be taken or not be taken. If there are uncertainties related to constrains such as environmental limits or other factors there is a chance that plant's flexibility is limited by human's extra precaution. Thirdly, the amount of time and resources available for planning and realizing a flexible operations is also important factor. These flexible operations might be limited due to a lack of resources that perform the necessary micromanagement required for each plant. Moreover, the time that can be used in decision making can be limited by other things. In those circumstances, issues such as keeping water levels within water right, are prioritized. (Crona 2012)

3.3.2 Production scheduling

Hydropower planning is generally divided into three planning periods according to a time frame: long-term, mid-term and short-term. Decisions made in longer-period planning are inputs for shorter-time planning. (Fosso & Belsnes 2004) The main idea behind production planning is same regardless of planning period. Decisions taken are driving by profit maximization, i.e. hydro companies try to maximize profit by selling energy and capacity when it is most profitable. Every planning period has to deal with uncertainties caused by inflow and energy and reserve market prices.

Long-term planning period varies from one year to decades. The main purpose of the long-term planning is to determine needed controllability and availability to maximize hydropower's profitability. This includes decisions such as installing new hydropower capacity or scheduling periods when production plants are not available due to a maintenance. Thus the long-term planning needs to deal with uncertainties caused by inflow and power demand. More precisely, factors behind these uncertainties should be considered. Is there some foreseeing changes in the power production system, climate change or political decision that could influence in power demand in future? Since some of hydro reservoirs allow to store water up to couple of years, long-term planning might need to take a stand on how much energy is produced weekly throughout the planning period. (Antila 1999; Scharff et al. 2014)

Mid-term planning period is from one week to 18 months ahead with weekly resolution. The purpose of the mid-term planning is to provide endpoint storage description in the form of incremental values for each reservoir, which are required in short-term planning. In mid-term planning, the reservoir content in the beginning of the planning period is known and the target reservoir content in the end of the period is result from the long-term planning. Then available energy is allocated to the time period so that the target level of the reservoir content in the end is reached. (Fosso 1999; Scharff et al. 2014)

Short-term planning horizon is from days to few weeks ahead with hourly resolution. The objective is to maximize the profits of the time scale through different market places. Hence, short-term model must take into account a complex configuration of cascaded reservoirs with each have different properties and constraints. (Wangesteen 2006) In the short-term planning inflow and electricity price can be predicted with sufficient accuracy. Forecasted values can generally be assumed to be right ones and when either one or both forecasts changes, the production can be optimized again. Hence, the short-term planning problem could be modelled deterministically. (Antila 1997) Mid-term scheduling gives boundary conditions which need to be adapted in short-term planning. Although mid-term planning gives boundary conditions for shorter period planning, these boundaries should not decrease the flexibility of handling possible variations in inflow. (Fosso 1999) Short-term planning is discussed more precisely in the coming chapters.

3.3.3 Decision making process

The operational decision making process is basically similar within every power generating company in Nordics. (Scharff et al. 2014) This process is presented from a hydropower company point of view in Figure 22.

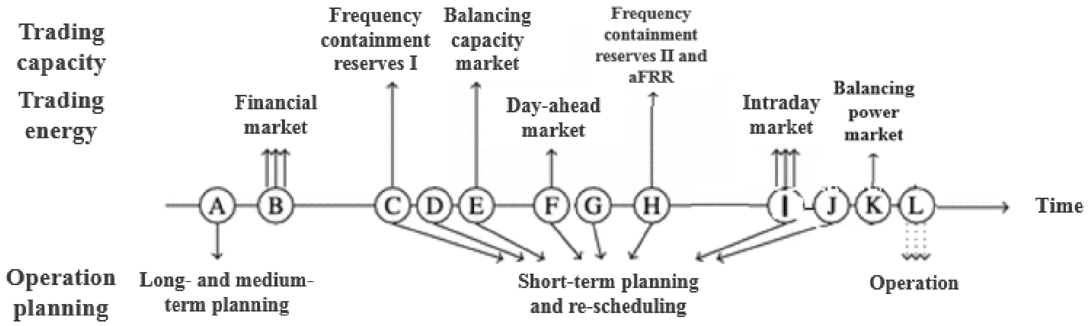

Figure 22. *Decision making points of hydropower company in Finland. The figure is reproduced from Scharff et al. (2014).*

A. Long-term and medium-term production planning, *years ahead.*
B. Trading on financial markets, *years ahead.*
C. Tendering process of yearly market: frequency containment reserves, *once a year for next year period.*
D. Short-term production planning, *weeks ahead.*
E. Tendering process for Fingrid's balancing capacity market; only if Fingrid decides so, *tender process once a week for the period of next week.*
F. Bidding on day-ahead market, *day ahead.*
G. Short-term production planning, *day ahead*
H. Second tendering process of reserves; for automated frequency restoration reserves and hourly frequency containment reserves, *day ahead.*
I. Intraday market trading, *hours ahead.*
J. Self-balancing, *hours ahead.*
K. Bidding on the balancing power market, *hours ahead.*
L. Operation in real-time, *hour of delivery.*

As can be seen from Figure 22, hydropower production scheduling is a continuous process which starts from long-term planning and ends with operating power plants in real time. Most of the decisions during this process are made discretely, but there are also sequent decisions which can be taken within a time period, such as trading in the intraday market or re-scheduling of power plants' production (Scharff et al. 2014).

The focus of this thesis is on actions done after the day-ahead market results and therefore the stages from G to L are discussed more precisely. However decisions made in earlier stages have to be taken into account, because they will most likely constrain allowed actions in intraday trading tasks. For example if some of the operated asset's capacity is reserved to yearly market of frequency containment reserves (with a reserve plan to the TSO), the capacity is not available in trading in other reserve markets, intraday nor balancing power market. Thus decision making is based on expected revenues from different markets. This means that lost revenue from one physical market should be less than revenue from the other market or else the tradeoff is not profitable (Wangesteen 2006). Hence, every time when bidding in one market, all the possibilities that other market places offer should be considered simultaneously in order to maximize profits. This type of bidding is referred to as coordinated bidding (Kongelf & Overrein 2017). If subsequent market places are not considered in the one market bidding phase, bidding is referred to as sequential bidding. (Kongelf & Overrein 2017)

Short-term planning becomes more precise when scheduling period is closer since forecasts related to hydro planning will become more accurate. The tasks of short-term planning can be presented in following way when the scheduling period is next day-ahead period. Firstly, short-term planning task is to decide how much capacity is available and at what price for the day-ahead market by preparing bid curves (stage F). In this point, the amount of available reserve, intraday and balancing power capacity should be taken into account. Secondly, after clearing of the day-ahead market, prices and own commitment is known. Then own production is optimally scheduled generator-specifically with aim to minimize production costs (stage G). In this stage, producer faces uncertainties such as energy prices in intraday and balancing power markets, power plant outages, predominant direction of system imbalance, energy realization of vRES and imbalance power prices. (Fosso 2005, Scharff et al. 2014)

In next stage (H), production plans for every asset is known and thus the available capacity can be offered to the frequency containment reserve and aFRR markets. According to (Scharff et al. 2014), uncertainties are congruent with stage H. Once production plans and thereby available capacities for energy trading are known, production plans can be adjusted by trading in intraday market (stage I). In this stage, producer decides if it is willing to adjust its' commitments by buying or selling energy on intraday market with the aim to maximize expected profits. When this decision is done, the producer does not know how prices of later intraday market trades will develop. In addition, balancing power market's realization, power plant outages and energy realization of vRES are uncertain. (Scharff et al. 2014)

Producer can re-schedule its production to match its own day-ahead and intraday markets commitments with the aim to minimize own generation costs and expected imbalance costs (stage J). (Scharff et al. 2014) This can be done until 45 minutes before the hour of delivery when the final production plans have to be submitted to the TSO (Fingrid 2017c). For some producers, re-scheduling can be beneficial alternative to trading in intraday market if the market liquidity is low. Whether it is profitable choice for the producer depends on the producer's portfolio of production plants, accuracy of generation forecasts and the imbalance prices. (Scharff et al. 2014)

If production plant has enough capacity to increase or decrease generation after re-scheduling step (K), it can be offered for up- and down-regulation to the TSO (stage L). By bidding on balancing power market, producer seeks to maximize its expected profits. Pricing of the balancing power market bids is based on the deviation costs that arise if production is altered from the optimal production plan that was scheduled before. Balancing power market activation and the length of the activation are uncertain for the producer since the TSO is in responsible for the real-time operation of the power system. In final step (L), production is operated according to the final production plan and changed if TSO activates bids on the balancing power market. (Scharff et al. 2014) Moreover, production output might change automatically if the unit produces either one or both of automated frequency restoration or frequency containment reserves.

4. TAKEOVER

In this thesis, the scope of taking over a river system comprises intraday activities: production planning of the operation day, bidding in the relevant market places and real time controlling of the hydro units. The purpose of the thesis is to determine how a control center without previous knowledge of a particular river system can take the river system over in a way that operation continues safely, yet profitably. To achieve this goal, there is an evident need to identify issues that either limit or give advantages to the power production of the hydropower system.

The main focus of this thesis is on intraday energy trading and real-time operating of hydro system. Hence, when considering taking over of an unknown hydro system, besides the optimization tools and models, personnel expertise is of great importance. This expertise is improved by training. Moreover, expertise will be built along the way when the hydro system is planned and operated.

This chapter focuses on the relevant topics that are essential in taking over of a hydro system but also in continuous work of the hydro producer.

4.1 Description

Before taking over, the river system was studied and the most of the needed models and tools such as day-ahead production planning optimization were completed. In the process of takeover, control center faced the following subjects concerning hydro system short-term planning and operating.

1. What are the subjects that need to be known?
    a. Permit conditions and other contracts that influence on planning and actual operating
    b. Hydro plant properties (discharge, spillage, production capacity, reserve capacities, efficiency curves, permits, delays etc.)
    c. Other limiting factors such as ice related issues
    d. Information exchange:
        i. Measurements such as produced power, water levels and discharge (which in many cases is generated from other quantities such as produced power and head level)
        ii. Fixed deliveries, production plans, reserve plans, reporting etc.
        iii. Interest groups
2. Which tools and models that are needed in production planning?
    a. Day-ahead energy market optimization
    b. Water level forecasting tool

   c. Intraday trading bidding model and tools
   d. Balancing power bidding tool
   e. Reserve bidding tools
3. How to carry out the trainings of personnel?

This thesis focuses mainly on the hydro system properties (part 1 a. – 1. c), intraday energy trading (part 2 c. – 2.d) and trainings of personnel (part 3).

With respect to part 1 a. – 1 c., subjects were studied from measured data, documents and by interviewing. These subjects are in key role when the necessary tools and models are built (Part 2). They are also important to the personnel who are responsible for the planning and operating of hydro production (Part 3). Information exchange (Part 1 d) such as production plans to TSO or measured water levels and discharges that are reported to Finnish Environmental Institute are basically fully automatized. In addition, measured water levels are used as one input to production planning and bidding.

When the hydro system is not previously familiar, many questions arise. In the later chapters, the presented topics are discussed. In order to understand the premise of river planning and operating which are in key role in this thesis, the responsibilities of relevant parties are presented in chapter 4.1.1.

4.1.1 Responsibilities

Hydro system regulation is carried out with co-owned company's hydropower plants and regulation dams. This co-owned company (referred as Party A) provides electricity to its shareholders, takes care of obligations towards environment and takes care of the operational capability of the hydro plants with out-sourced service of maintenance (referred as Party B). Party A might also give guidelines to regulation done with regulation dams in the upper reach. Hydro system production is planned, traded and operated by control center (referred as Party C). From here to throughout the thesis, these parties together form a hydro producer.

In addition to those duties, hydro producer's control center can also help in planning of timing of maintenance works because it has better insight at the markets in which it continuously operates. For instance, sudden but not immediately needed maintenance, (i.e. not failure) can be scheduled on the time when it is most feasible to compensate energy that cannot be produced during maintenance if maintenance personnel and Intraday Trader of the control center co-operate. Hence if we assume that the maintenance is needed within operation day, the compensation of production stoppage can be bought from intraday market or perhaps by utilizing other hydro units capacity if feasible.

Different resources are needed when operating in electricity markets as power production company. One highly important resource are humans which are needed in tasks of planning, balance management, maintenance, management, development work and back-office. Another crucial resource are information systems which are used in implementing of in-company tasks but also for information exchange between relevant parties.

In this thesis, relevant human resources of the hydro producer are all involved in physical trading of power. There are four Physical Traders who are in responsible of hydro power optimization from mid-term planning to daily day-ahead bid optimization. Thus Physical Trader is responsible for the day ahead process which will finally give production plan for coming day-ahead period. This production plan of the river system is operated by Intraday Trader who can alter production from the original production plans by trading in intraday or balancing power markets. Main drivers that strive Intraday Trader to re-schedule hydro production or bid in intraday or balancing power markets are the possibility to increase economical profitability and to manage water levels. In addition, there might be need to trade in intraday market to minimize economical risk if hydro production cannot meet its day-ahead obligation.

Information systems needed in this thesis are Energy Management System (EMS) and Operations Control System (OCS). Main properties of EMS are:

- Optimization tools
- Energy and reserve bidding tools
- Data collection and reporting
- Numerical and visualized forecasting
- Automated information exchange

Hydro optimization can be done with optimization framework built in the EMS. In addition, one can create tools in Microsoft Excel and include those to the EMS. The support in decision making of hourly production allocation which optimization model provides, is in great importance especially when the personnel does not have a much experience on the river system.

Hydro production related data is collected to the EMS. Based on the collected data such as reservoir levels and hydro plant’s discharge it is possible to provide production plans and forecasts of water balance situation to the becoming hours. In addition, personnel can learn from the data by evaluating how good decisions he or she made.

EMS enables automated both-way information exchange between control center and stakeholders. As an example, the river’s production plans are firstly calculated in the EMS and then automatically delivered to Fingrid via EDI messaging.

The role of the OCS was minor in this thesis, because all the trading activity and information exchange is either done or linked with EMS. Main properties of OCS are:

- Real time controlling
- Real time data measurement
- Information exchange between it and EMS
- Events and alarms

Even if the OCS is in minor role in this thesis, it might be good to underline that the OCS is vital to the control center: it is used for real time hydro operating and for gathering of data but also for reporting events such as openings of circuit-breakers and giving alarms or warnings based on determined limit values and conditions. For instance, alarm or warning can be given about faults in hydro unit or about high (or low) hydro plant's reservoir level.

4.1.2 Problem description

In the terms of service agreement between of Party A and Party C, it is agreed that the river production is planned optimally against forecasted day-ahead market price. Therefore, at least at the moment, the subsequent market places are hardly considered in the day-ahead bidding process. Hence, day-ahead results obviously sets well-defined boundary condition to the trading possibilities in intraday markets. However, there is possibility to increase production profitability with reasonable intraday bidding.

One of the key objectives of this thesis is to develop a method for intraday energy bidding, i.e. provide automatically calculated bids to the markets in relation to marginal cost of production. Ideally, this should increase additional value created during operation day because gaining possibilities are strongly time-depended. For instance, intraday market continuous trading principle is first come, first served and therefore it is crucial that control center knows continuously how much and at what price it is willing to buy and sell its hydro production. In addition, automated bid calculation enables hydro producer's control center to focus on other tasks.

To be able bid without distorting profit margins, there is evident need to consider method for bidding and survey hydro characteristics of the studied hydro system. Moreover personnel whose is in charge of operating of hydro plants must be familiar with the hydro system. Therefore, the training of personnel is in key role when taking over a previously unknown river system and utilizing its available flexibility. This problem description is elaborated further in chapter 4.6 after presenting hydro system and the learning process of the control center's personnel in chapters 4.2 – 4.5.

4.2 The river system

This chapter gives an outlook on the hydro system in question by presenting its main properties. The river system is located in Finland.

4.2.1 Hydropower and catchment area

The catchment area of the river system in question is 14 191 km^2 and 5,7 % of this area are lakes. This thesis focuses on the main channel of the catchment area where the hydropower plants are located but also some of the most important lakes (reservoirs) are studied.

Properties of this area are the lack of big lakes and the fact that the lakes are mainly situated in the upper reach. Hence the flow of the main channel reacts rapidly to fluctuating inflow caused by prolonged precipitation or melting of snow. For this reason, the studied river has usually faced a heavy spring flood.

Simple illustration of relevant parts of the river system in question is presented in Figure 23. Hydropower plants are identified by letter *P* and water reservoirs are marked by letter *R*. All regulations carried out in the river system are operated by control center. *R3* is the only nonregulated object in the system shown in the figure below.

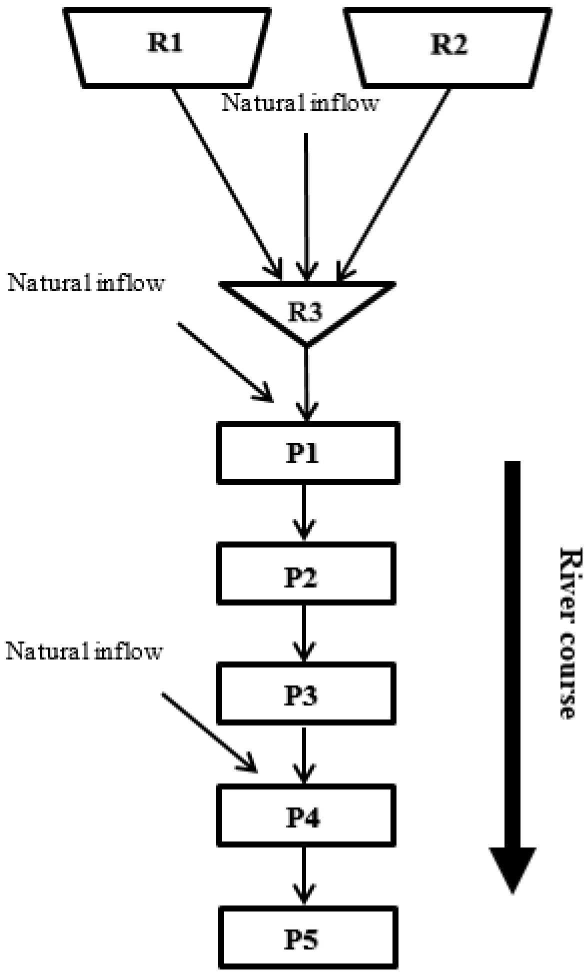

Figure 23. *Topology of the examined river system.*

In Figure 23, the river system is presented with only three reservoirs *R1*, *R2* and *R3*. In reality, there are numerous lakes in the river system. Hence, the question that the hydro producer has to consider is generally following: what are the main reservoirs that are needed in modelling of hydro system and what are the delays between them? Moreover, if there are regulated reservoirs, how their water content changes with the difference between inflow and outflow and what are the valid regulation constraints that need to be considered. Finally, how inherent lakes behave in different circumstances. Good knowledge about river system's reservoirs is crucial in electricity production but also in the flood control.

Regulated water reservoirs *R1* and *R2* are situated in the upper reach of the river. Non-regulated reservoir *R3* gathers outflows from the regulated reservoirs and run-offs between it and the regulated reservoirs. Its area and volume is relatively small, and it is more like an expansion of a river. Therefore, its level changes quite rapidly if there is a difference between inflow and outflow. Distance between the regulated water reservoirs and hydropower plants is long: water discharged from reservoirs *R1* and *R2* arrives in the plant P1 after time delay of eight to nine days.

Due to long distance between the regulated reservoirs and hydro units, the river flow in the down reach where the hydro plants are located is highly depended on the hydrological situation of the catchment area. For instance, in wet conditions, the river flow increases remarkably without an increase in the discharge of the regulated reservoirs. Both regulated reservoirs are drained before spring flood in order to keep water level between allowed levels with minimum discharge during flood time. Minimum discharge during flooding have positive influence on both man-made environment and hydro producer. This minimum discharge during flood time can reduce economic damages experienced by humans. From the electricity producer point of view, it is economically viable to save as much water as possible to the reservoirs *R1* and *R2* since all added discharge would only increase the spillage of hydro plants when inflow of the hydro plants exceeds the discharge capacity of the turbines. Inflow forecasts are of great importance when making regulation decision for the reservoirs *R1* and *R2*. For instance, if realized inflow during the flood is remarkably below the forecasted one, it might mean that the target reservoir levels will not be met after the flood. This might be harmful for the recreational activities of lake but also the power production capability is limited in respect to mid-term plan.

From the day-ahead and intraday hydro production planning point of view, outflow from the *R3* is in key role because it represent the major part of the inflow that arrives in hydro plant *P1*. The minor part of *P1* inflows comes from the local inflow that falls to the river bed below the *R3*.

Hydro plants *P1 – P5* are situated within short distance in the down reach. The discharged water from the plant *P1* travels through the chain of plants roughly in two to three hours.

The water discharged from the plant *P1* arrives in the plants *P2 – P5* as inflow. Furthermore, there are noteworthy run-offs between plants *P3 – P4* which increases the inflow to plants *P4* and *P5* occasionally.

While each plant is presented as a ROR plant in Figure 23, in reality every plant has a small storage capacity due to a minor reservoir above, allowing temporary short-term regulation. Since the plants are nearly run-of-river plants, the regulation potential is highly depended on the river flow that arrives in hydro plants. In practice, the hydro plants *P1* and *P5* have largest reservoirs and hence they are most suitable for daily regulation while the rest of the plants are mainly operated and planned as ROR plants. Each plant reservoir volume is illustrated in the chapter 4.3.1.

4.2.2 Constraints

The starting point of capturing previously unknown hydropower is to observe valid regulation permits, other contracts and plants' constraints which determine how hydro system can be operated. Constraints are typically included in planning tools alongside other hydropower production features.

Regulation permits and constraints

Each reservoir has its individual maximum and minimum water level limits which can vary according to seasonal or momentary conditions. Regulated reservoirs (*R1* and *R2*) upper and lower reservoir limits changes seasonally according to predefined dates (see Fig. 24), whereas hydro plant's upper reservoir limits are fixed. The permit can define momentary conditions, such as extremely high discharge, which in turn changes allowed reservoir level limits momentarily. This is the case with the hydro plant *P1* which upper limit reduces when the river flow exceeds 600 m^3/s.

The permit might also set constraints for discharging. Such permits can be limitations on how quickly discharge can be altered or requirement for minimum discharge on daily or hourly basis through water structure. In the studied hydro system, the permit requires minimum daily average flow in the river but does not restrict the hourly minimum and therefore it is possible to stop production and the water flow in the river parts between hydro plants. As a summary, the permit determines maximum amount of water that is available for regulation and in some cases can constrain how this regulation can be executed. Hydro producer must carry out the regulation in such way that reservoir or discharge limits are not infringed.

There are also other constraints or guidelines than previously mentioned that need to be considered in hydro production. Such constraints or guidelines reduce the flexibility which would be available with the individual permit. Besides the permit's water level limits, there might be recommended levels in which a reservoir should be kept (see Fig.

24). Moreover, there might be contracts between the hydro producer and stakeholders concerned on how regulation should be carried out. Perhaps the most common reason for these contracts is to bring back some of the natural features of river. For instance, there might be contracts concerning supporting of fish movement or contracts which purpose is to improve the ecological state of the river system. Both of the previously mentioned issues are in great importance in the regulation of the river system in question.

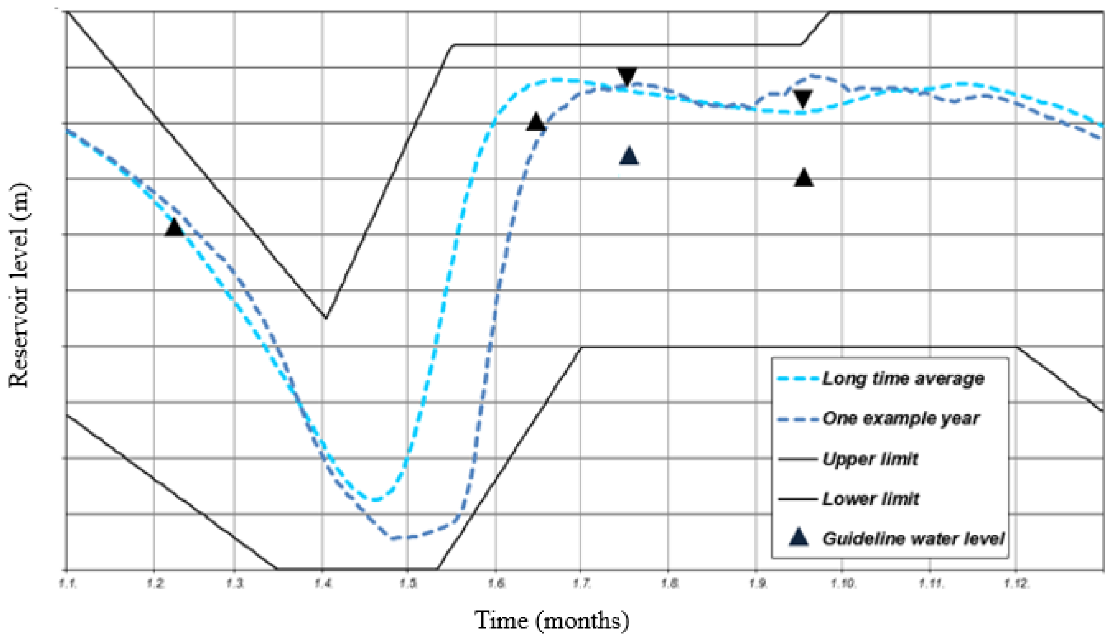

Figure 24. *Regulation of a water reservoir with level constrains. Upper and lower limits are based on the water permit and thus they are strict but guideline water levels are recommendations that hydro producer aims to follow.*

Hydro plants constraints

In addition to discharge and plant reservoir level limits given by the regulation permit, hydro plants' have physical and technical limitations that need to adapt. Relevant properties that are typically interesting in the eyes of hydro producer are related to the discharge capacity and power production capability.

To begin with, every plant has its minimum and maximum discharge capacity through turbine(s) and flood gate(s). First one is related to energy production and the latter is important not only because of flood control but also in sudden situations. A person who is responsible of controlling the plants must know how much water can be discharged through the flood gate which is decided to be used (if there are multiple flood gates) in the case of sudden need for spilling of water.

Secondly, every plant has its generator-specific minimum and maximum power output which determines the available range of energy that can be produced with the particular hydro plant. Especially, the maximum power output is depended on the hydro plant's head and therefore it depends on the unit intake level and tail water level which both are related to the discharge of the plant in the studied river system. In the production range, there might be also forbidden production zones due to cavitation of the turbine. Occasionally, there is maintenance work which temporarily constraints available production range of one or more of the hydro units. In practice, in the extremely strongly hydraulically coupled river system like the studied hydro system, one plant's production limitation will effect to the production capability of the other plants if the limitation takes several hours.

Finally, hydro units have a possibility to provide frequency support with its spinning reserve capacity (FCR). These capacities, verified by Fingrid, need to be known in order to be able bid in the reserve markets.

4.2.3 Other conditions

Besides the hydro system properties, there might be other external conditions that constrains how hydro system can be operated. In the studied hydro system, the other constraints are mostly related to weather conditions such as ice related issues and faults caused by lightning. It is though noteworthy that these are rather rare situations at least when considering day-to-day operation of the hydro system.

Ice related issues can set momentary constraints to hydro system operation. Firstly, in winter when it begins to freeze outside, producer need to consider how the ice-cover can be most cost-efficiently formed. In the studied river system, the ice forming capability differs between different hydro plant reservoirs. Hence, some of the hydro plant reservoirs are harder in terms of forming ice-cover. Typically, hydro plants discharge and production altering is limited during the time when it is enough cold in order to form ice-cover. Secondly, in convenient circumstances during the time of ice-cover, hanging dams might be formed in the river part below the regulated reservoirs (*R1*) and (*R2*). In those circumstances, water level of concerned river part rises and some of the surroundings are covered in water. This can be harmful for the buildings and for the environment.

Production might be limited due to limitations or faults in the power grid. For instance, there might be restrictions on how much power can be transmitted in some abnormal situation. In those circumstances, the power produced by a unit is fed to the grid via backup connection which power handling capacity might set some limitation to power production. In addition, lightning might cause a fault in which one or more units electricity production is limited.

4.3 Hydro system features

The optimal production rate is sum of many factors. It depends on hydropower units' individual features, realized or forecasted price of different market places and forecasted water inflow. The individual features such as turbine efficiency curves and head losses for higher discharge are more or less constant but estimations on future prices and inflows are uncertain. From the studied hydro system planning point of view, it is important that each units features are modeled correctly but since the plants are strongly hydrologically coupled, the question is how the examined hydro system can be utilized to capture as high water value as possible.

Each individual feature should be modelled with sufficient accuracy, because they are interconnected to other features. Hydro units in question are operated by planned energy, thus forecasting error in the head leads to an error in the hydro units' head depended discharge, which in turn can lead an forecasting error in the reservoir level.

In this thesis, production planning is considered from intraday point of view. However, longer optimization periods share same hydro assets' features than intraday trading and thus results from this thesis can possibly be used for the benefit of short and mid-term planning.

4.3.1 Plant reservoirs

Hydro plant's reservoir is modelled with their cubic volume (m^3) which in hydro power context can be more handily presented as an Hour Unit (HU). Hydro production is planned in hourly basis, and the Hour Unit converts reservoir volume to hourly volume since it is defined as the volume cumulated from discharge of 1 $m^3/_s$ during one hour, resulting volume of 3600 m^3.

The plant reservoirs are presented in Figure 25 with comparison of how large percentage their reservoir volume is in relation to total reservoir capacity which includes all plants' reservoir volumes added together. As Figure 25 illustrates, the hydro plants *P1* and *P5* have greatly larger reservoir capacity than the rest of the plants and thus they seem to have the greatest potential to daily regulation. However, due to physics of the studied river system, the discharge of the plant *P1* mainly determines when and how much water is available for the sequential plants. Thus *P1* cannot be regulated independently without having major impact on sequential plants operation. For instance, when *P1* is running with its full discharging capacity (through turbines) it can lead to a situation where the reservoir of the subsequent plant is filled up and since the *P2*'s discharge capacity is slightly lower than the plant *P1* there are no more discharging capacity left to increase.

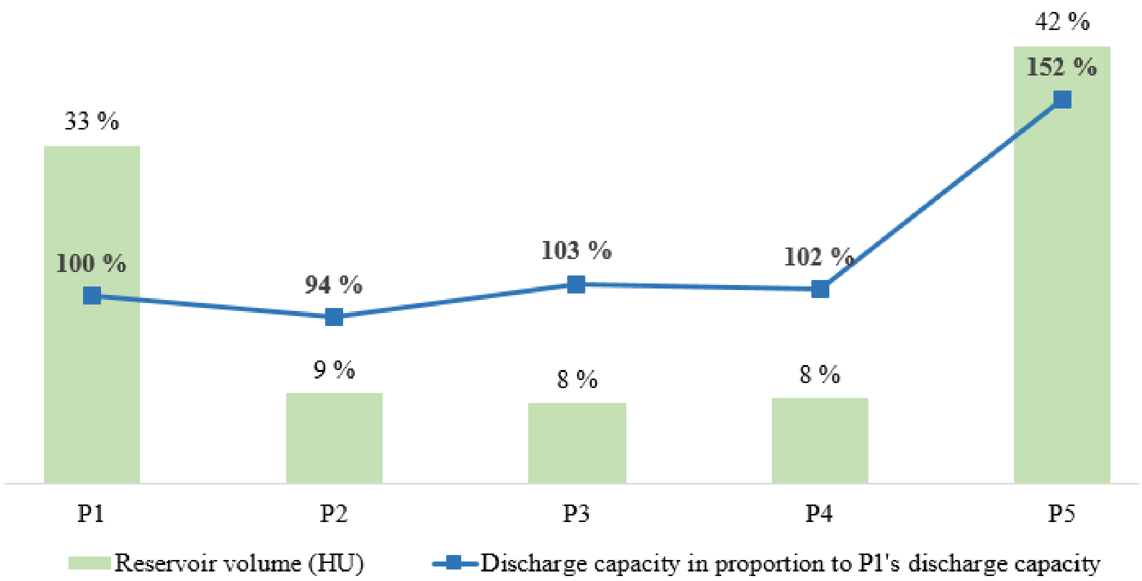

Figure 25. *Reservoir volumes as shares of the total reservoir capacity. Discharges in plant's discharge capacity in proportion to P1's discharge capacity.*

Each plant's reservoir level of hydro system are measured in real time and forecasted for future hours based on the water balance i.e. planned outflow and either planned or forecasted inflow and piecewise linearly modelled reservoir volume. In practice, this means that the reservoir storing volume is assumed to be change linearly for each fixed part of the reservoir. Thus in order to produce realizable production plans and bids, reservoirs must be modelled with their correct volume in reference to reservoir level.

Figure 26 presents how quickly reservoir is filled up (drained) if it is fulfilled (emptied) with greater (smaller) reservoir's inflow than outflow. From Figure 26 we can conclude that the *P1* dictates downstream plants possibilities to product energy and therefore its' discharge is dominant factor of the river's total production. Nevertheless, plant *P5* have both reservoir and discharge capacity to regulate its' electricity production independently to a certain content.

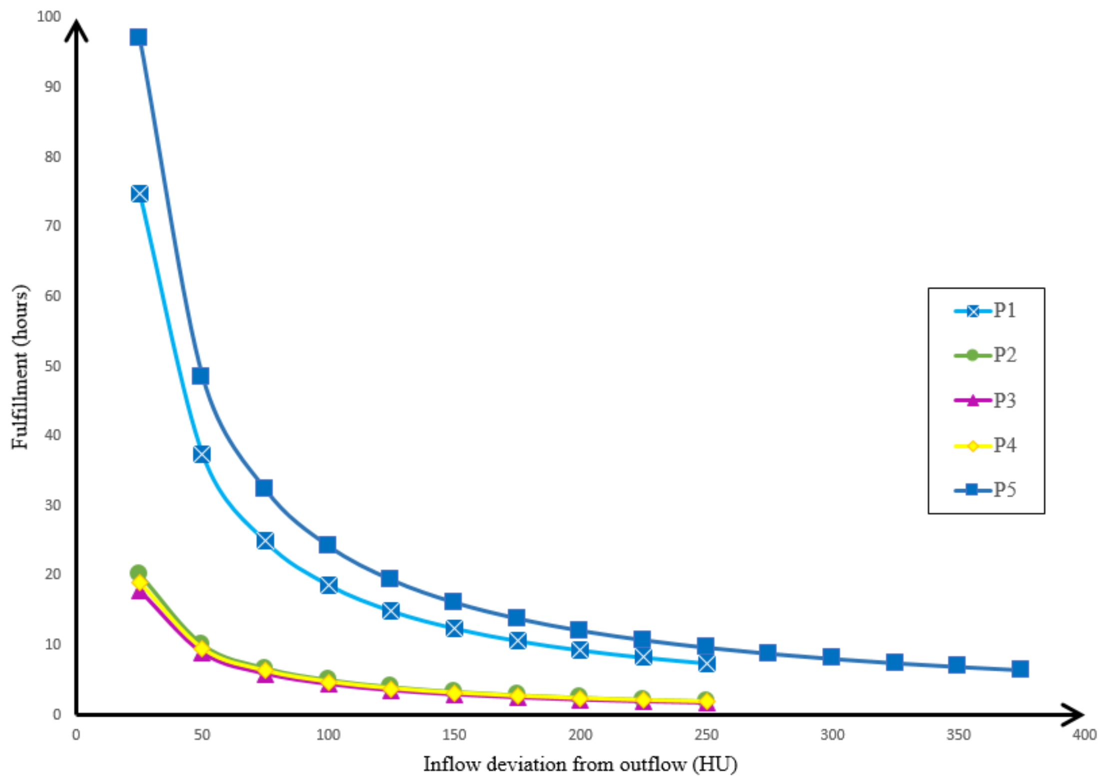

Figure 26. *Hydro system's plants' reservoirs fulfillment time (h) as function of the inflow vis-à-vis the outflow in Hour Units (HU). Minimum and maximum x-axel values for each plant are based on their discharge capacity.*

Because the reservoirs of plants *P1* and *P5* have 75 % of the hydro plant's total storage capacity, they basically sets how the hydro system can be operated. Moreover, the rest of the hydro reservoirs are significantly smaller and hence their potential is harder to optimize because they might be ran out of water within one to two hours. Additionally, if the all of those are "drained", their fulfillment is harder to be done in a way that is economically reasonable. Therefore, it is easier at least in this master thesis to assume that the main potential for intraday market trading comes from the hydro plants *P1* and *P5* reservoirs.

Hydro plant's reservoir levels need to be estimated with high accuracy in relation to water balance. This is crucial for the day-ahead planning perspective but also for bidding and re-scheduling purposes during operation day. Consider bidding in intraday markets: The reservoir plans are available and therefore the basis for the net head level is available. Then, if the discharge from the plant reservoir is altered by increasing or decreasing discharge through the hydro unit within one hour, the effect on reservoir has to be considered. With significant reservoir, the reservoir volume could be assumed to be same during one hour even if the hour's discharge is altered (Skjelbred et al. 2017). When it comes to the small-sized reservoir, the intake level reacts more rapidly to the difference between plant's outflow and inflow and therefore it might be necessary to estimate how the intake level will change if the discharge is altered. This estimation and the water balance are needed in estimation of possible bidding points, i.e. production level and price.

Reservoir level influences the efficiency of production but also the maximum power output. Therefore it is relevant to consider how this reservoir level dependency can be modelled in production scheduling. As a starting point of intraday bidding and re-scheduling, there are forecasted reservoir levels available due to day-ahead scheduling. Then the question is, how to take this influence on net head level into account when bidding in the intraday markets.

One, fairly simple approach is to assume that reservoir level is constant, for instance always at the maximum level. This is not however realistic if the variation in the reservoir level is a fairly large percentage of the overall hydraulic head. (Garcia-Gonzalez & Castro 2001) In those circumstances, there is at least two potential approaches available. Firstly, it is possible to form multiple production curves for variable head or reservoir volume (v) with a function of a discharge (q). The production curve which is expressed as $P = P(q, v)$ can be non-concave as can be seen from Figure 27. (Garcia-Gonzalez & Castro 2001)

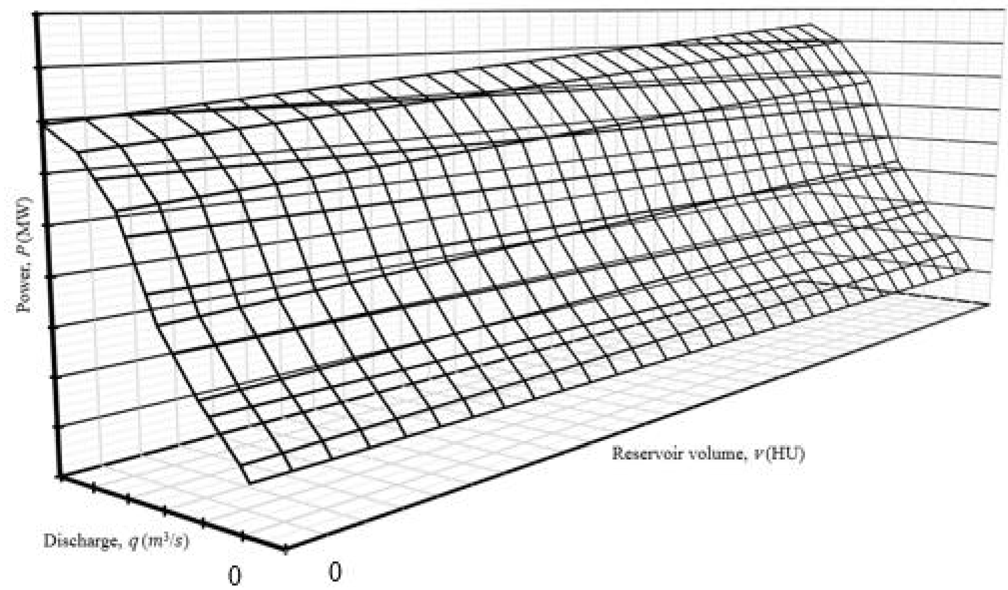

Figure 27. *Production input-output surface of plant P1's hydro unit.*

From Figure 27, we can see that for a given reservoir volume, power increases when discharge increases. In addition, for given discharge, power also increases when reservoir volume, i.e. net head increases. (Garcia-Gonzalez & Castro 2001) Based on the forecasted reservoir level and tail water of one hour, it is possible to determine which of the production curves is relevant for the prevailing situation and therefore is most suitable to production efficiency estimation.

Another viable method for head-depended production modelling is, at least in intraday trading purposes, to estimate the net head from the forecasted values of reservoir level and tail water. Then we can calculate how the head will change if the plants' discharge is altered. This is convergent method with a research paper that provides a practicable assisting method for hydro producer for trading in intraday energy markets (Skjelbred et al. 2017). Net head can be then taken into account in hourly basis with the shown equation (9) in chapter 3.1.1. Both methods are based on the same physics of a hydro plant, but the second method could perhaps be more accurate than the first one if we use too few production curves when utilizing the first method.

Considering a case where hydro production is increased. If the whole reach is operated as a one plant, then the only hydro plant that is clearly exposed to effect of lowering reservoir level is the plant *P1*. Assuming that the discharge is ramped up simultaneously and equally at every hydro plant. While every plants' outflow increases almost immediately, the inflow also increases, but only after a delay, in all plants except in hydro plant *P1*. Thus, the reservoir level change in all other than *P1* reach the stationary state after a delay. In reality, the delay between *P4* and *P5* might be too long for this assumption and therefore *P5*'s reservoir level change is reasonable to take into account in a same manner as with hydro plant *P1*. Moreover, the discharge capacity of *P5* is greatly higher than the previous plant and therefore its reservoir level will decrease anyway if its higher capacity is used.

In hydro plant *P1*, the difference in production output for a given discharge value varies approximately at the most 15 – 20 % with minimum to maximum reservoir level. This is undoubtedly a significant efficiency loss. However, the relevant question is whether this efficiency loss can be outdone with the rest of the plants that have better water availability and higher reservoir levels if the whole reach is optimized and operated as one plant.

It should be noticed that models can develop further once experience is gathered. Thus, in the point of taking over of a hydro production planning and operation, questions like how the reservoir level and its change should be modelled in the intraday bidding purposes need to be considered but the development process for those can perhaps be longer.

4.3.2 Delays

A necessary part of hydro planning and operating is to model water movement between hydro systems' reservoirs with high accuracy. Proper knowledge of water delays is needed in order to produce realizable and profitable production plans in the day-ahead market but moreover they are needed when generating bids to intraday and balancing power markets. If water movement is not adapted in the intraday bids, it might cause decrease in overall income. Considering a case where there are two cascaded hydro plants with plant reservoirs and the subsequent plant has limited discharging capacity during a day for period of few hours and its' reservoir is planned to be fulfilled with the previous plant's discharge during the nighttime. By neglecting water delay between the plants, one or more hours of the previous plant's up-regulation bid realization might cause undesirable increase in subsequent plant's production for hours that are not attractive in the eyes of hydro producer. In addition to delays between hydro plants, there are also other delays to be considered.

Water movement between hydro plants

In the river system, hydro plants are located within short distance from each other. The shortest distance between two cascaded plants is approximately 6 kilometers while the longest distance is approximately 19 kilometers as can be seen from Table 3.

Table 3. *Hydro plants distance between each other and water delays.*

	Distance (km)	*Delay (min)*
P1-P2	*10*	*22*
P2-P3	*6*	*24*
P3-P4	*14*	*37*
P4-P5	*19*	*60*

In Table 3, delay means the time when discharge change starts to influence on the subsequent reservoir. In the planning tools that were done before the actual take over, the delays are neglected apart from the delay between *P4* and *P5* which is modelled with fixed delay of 60 minutes. In the intraday bidding purposes it might be necessity to include delays in the model. Next we discuss about the modelling of the delays in the river system.

Neglecting delays of the river system might in some cases be problematic and lead to unwanted results in intraday re-scheduling and bidding. Considering a case when a hydro plant *P1* discharge is forced to be ramped up due to arriving inflow in an hour (t) that price is not as desirable as next hour's $(t + 1)$ price. If the hydro plants *P2 – P4* reservoir are full they are forced to dispatch with same discharge as the previous hydro plant since there are no water delay between hydro plants. If delays are included in the modelling, subsequent plant's discharge does not necessarily have to be as high as the previous hydro plant and thus production can be saved to hour $t + 1$ when the price is more desirable. Similarly when decreasing production, including a delay could be beneficial. In the studied hydro system, it is not realistic that hydro plant which reservoir is full could decrease its production unless the inflow to the reservoir is not declining at the same time.

In the studied hydro system, actual inflow to the a hydro plant can be estimated for instance with simple exponential smoothing:

$$S_t = \alpha x_t + (1 - \alpha) \cdot S_{t-1} \quad (12)$$

Where α is a smoothing factor which weights the current value (x_t) and the previous time period smoothed value (S_{t-1}). Therefore the restriction of $0 < \alpha < 1$ must hold true for the smoothing factor. The factor increases with the increase of weighted value of current period. An illustration of smoothed delay is presented in Figure 28.

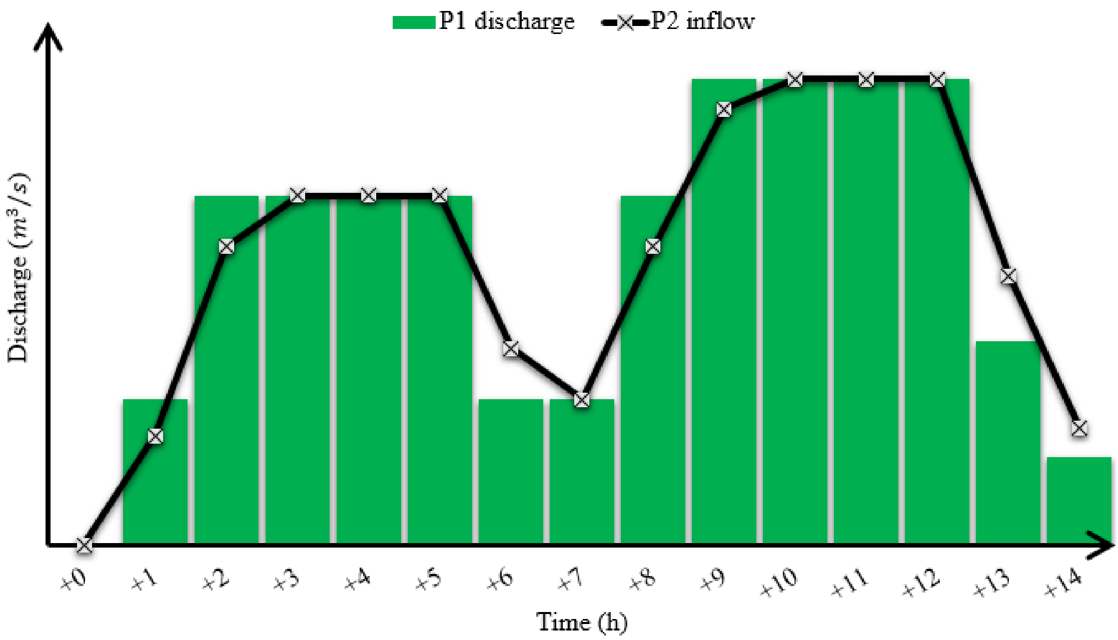

Figure 28. *Exponentially smoothed inflow in the subsequent hydro plant with smoothing factor 0.75.*

With delay of *P4 – P5*, there could be a need to model more precisely how the amount of discharge from plant *P4* influences to delay time, because for instance if hydro producer is willing to stop the plant *P5* while there is still arriving more water from the plant *P4*, it would be essential to know that there is enough room for arriving water in the reservoir of plant *P5.*

Moreover, it was identified that water movement in river part between plants *P3* and *P4* should be examined more closely. Firstly, hydro plant *P4* optimal operating differs from the others because its plant permit's water level is measured from 6 kilometer above the plant. Thus the delay between the permit water level and the previous plant is less than delay from the plant to the permit level. For this reason, hydro producer can more quickly affect the water level with discharge change of previous plant than with plant *P4.* As a conclusion, if both plants *P3* and *P4* are ramped up at the same time, there need to be enough room for river level to increase in the plant *P4* water permit location. Vicinity of plant *P4* is illustrated in Figure 29.

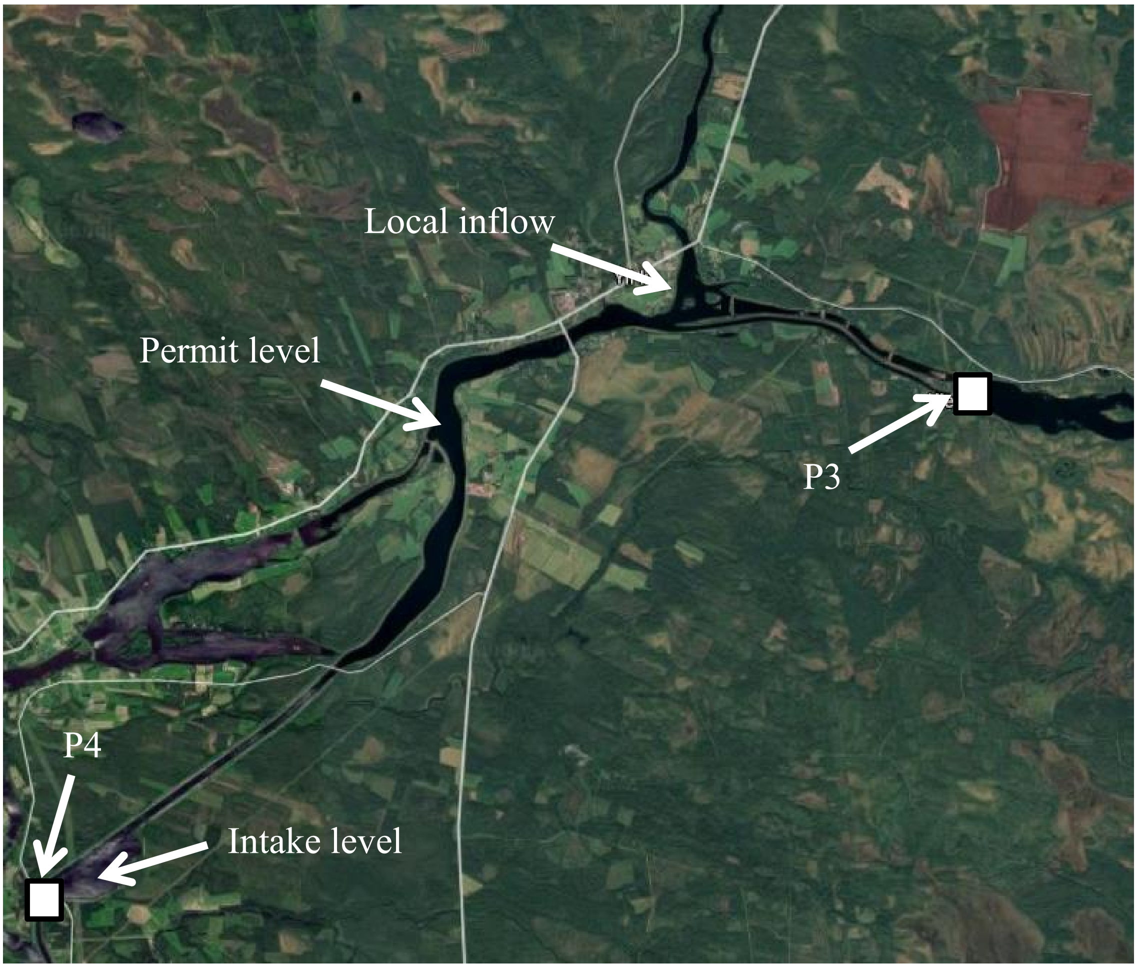

Figure 29. *Vicinity of plant P4: water level measurements located in intake but also further where plant's permit is exclusively linked. Local inflow is most significant of the tributaries falling to the river bed.*

Secondly, most noteworthy local inflow arrives as inflow to the plant *P4* as Figure 29 shows. This inflow can be difficult to forecast especially in circumstances where the amount of inflow changes rapidly due to excessive rainfall, for instance. Basically the side stream's flow is forecasted by Finnish Environmental Institute which provide daily forecast for use of hydro producer. However it might not be enough in all circumstances, since day-ahead market for next day closes at 13:00 EET, there is time period of 36 hours in which day-ahead obligation is closed and hence producer cannot affect its own obligation even though inflow might be differing from the forecasted.

Water levels related to hydro plant *P4* can be seen as good example of difficulties that hydro producer might face. How these water levels can be modelled in a way that the hydro plant *P4* operation i.e. water balance and production can be sufficiently estimated. Therefore, producer need to have models for both of the level measurements related to the plant *P4* because intake affect to energy production and permit level must not be infringed.

As a conclusion, delays are essential in profitable bidding and re-scheduling. Better knowledge of water movement will lead to more accurate match between forecasted and realized reservoir levels once production is realized as planned. The more accurately hydro balance of a hydro plant is estimated for future hours, the more accurately we can estimate the prices of its production flexibility. Delays are important part of overall production scheduling and bidding from day-ahead phase to balancing power and therefore it would be beneficial to include all delays between hydro plants in day-ahead planning. We will use the smoothed delay presented in Figure 28 for all delays between hydro plants when calculating the hydro system's bidding volumes and prices related to them.

Other delays

As earlier mentioned, regulated reservoirs *R1* and *R2* are situated far from the cascade of hydro plants. Thus there are also other inflows that fall to the river bed and hence the water arriving to the first hydro plant is gathered along the way. In that way water released from the regulated reservoirs will only represent part of the inflow to the hydro plants. Naturally its share of total inflow varies depending on time of year and water content in the reservoirs. All of the gathered water is firstly "stored" in non-regulated reservoir *R3* which discharges continuously. This discharges can be approximated from discharge curve which is based on water level measurement of reservoir *R3*. It has been noticed that discharge that arrives as inflow to the hydro plant *P1* can vary rapidly during time of ice cover probably due to a frazil ice conditions in the river part between reservoir *R3* and hydro plant *P1*. This basically means that inflow to the hydro plant *P1* can decline rather quickly in those circumstances if water movement in the river bed is restricted. On the other hand, once frazil ice conditions ends, the inflow can quickly increase.

In the day-ahead planning, this kind of phenomena might be hard to evaluate due to the fact that circumstances in river bed might be rapidly changing. Additionally, mainly during open water time, inflow to hydro plant *P1* as well as *P4* can increase or decrease during day-ahead period depending on weather conditions. During winter, the changes in inflow are typically more moderate. Intraday Trader's task is to handle changing inflow during the operation day and decide how to deal with the imbalance between original plan or forecast and changed inflow.

4.3.3 Efficiency of production

Every hydro turbine has its best production zone in which it maximizes produced energy per volume of water. If there would not be any volatility in the electricity prices and reserve markets possibilities are ignored, it would be advisable to run each turbine with the optimal production level and high intake level to maximize profits from produced electricity. That is, there would not be reason to hourly production allocation. In reality, the market prices are volatile, showing higher prices during mornings and day-times than in nights and weekends. Moreover, the reserve markets offers possibilities to increase profits. Therefore it is reasonable to produce electricity and reserves when the trade-off between the efficiency and profits is favorable for the producer.

The trade-off concerning energy production, is mainly depended from turbine efficiency and head level losses. In this chapter, there is first discussion on the tail water losses and how them can be modelled in the hydro system in question. Then, the intake level losses are studied. These tail water and intake level behaviors are needed in the marginal cost pricing of production which is presented in the chapter 4.4. The head level losses in meters have been heuristically analyzed from historical data. Since the analysis is based on the data it is possible that some of the estimations are incorrect. Therefore in future the model could be perhaps improved by implementing tests for head level losses.

Tail water typically rises when a hydropower plant's discharge is ramped up. The tail water behavior of a hydro plant can be modelled with a conventional method, in which the tail water is modelled as a linearized function of the total discharge through the plant's turbines and spillways. Another rather simply method for modelling of the tail water of the hydro plant is to assume that the tail level changes linearly according to the discharge change. From the river system in question point of view, the latter method could be more exact model with the tail water behavior of the last hydro plant (*P5*) in the river basin because it releases water to the sea which level varies from time to time. An example of described model for the hydro plant *P5* is presented below in Figure 30.

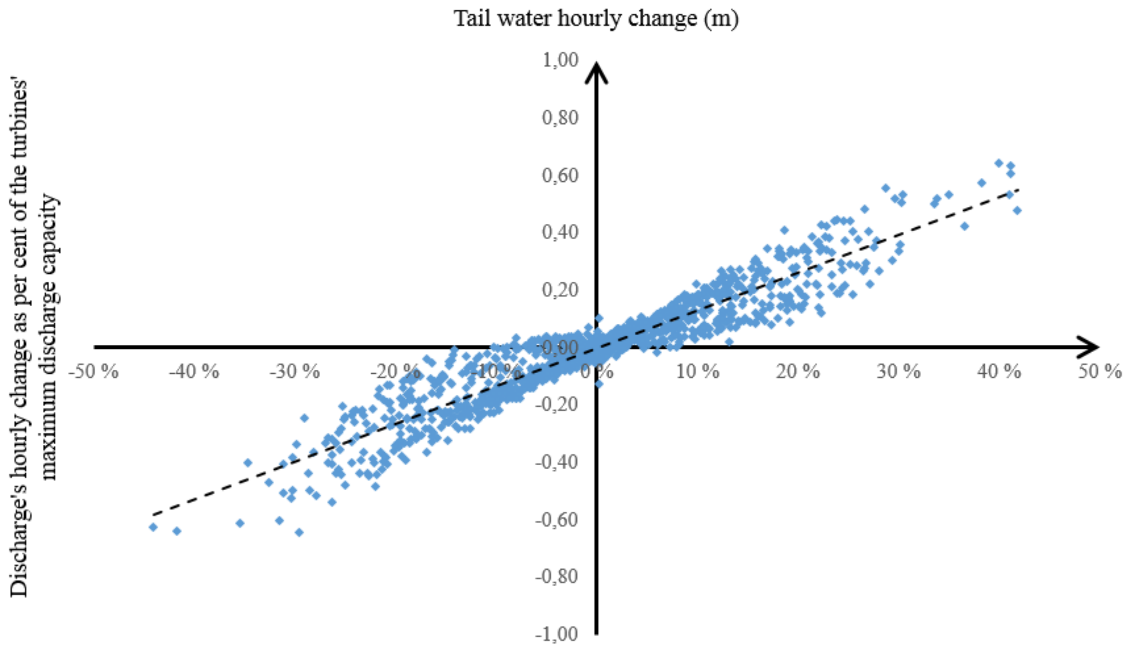

Figure 30. *An example of an linearized hourly tail water level change with function of hourly discharge change as per cent of the maximum turbine's discharge capacity according to statistical data.*

The linearized hourly tail water level shown in Figure 30 will result a forecast for the tail water level once we know the prevailing tail water level (or forecast) and the forecasted change in hydro plant's discharge.

However, with strongly hydraulically coupled hydro plants, the tail water could be located in subsequent hydropower plant's reservoir. In these circumstances, the tail water is influenced by the downstream reservoir level. In Figure 31 there is example of this dependence, and moreover the figure illustrates one possible method to estimate the tail water of the previous hydro plant when hydro plants are located close to each other. Data is from the plants *P1* and *P2* which are located 10 km away from each other.

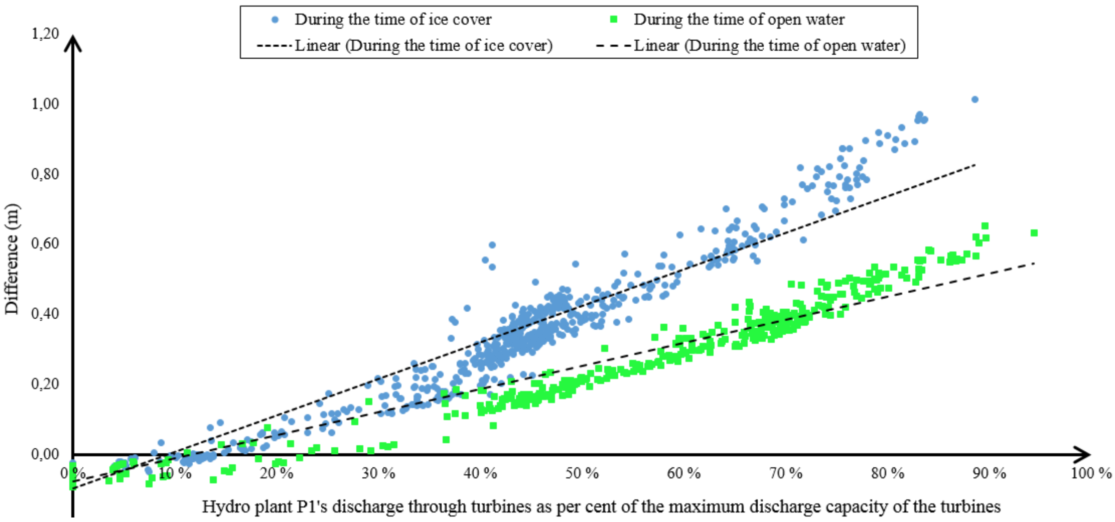

Figure 31. *An example of linearized tail water behavior of a hydro plant that takes the subsequent reservoir into account. Difference is determined as difference in hydro plant P1's tail water and subsequent reservoir level in hourly basis.*

As Figure 31 visualizes, in a case where hydro plants are located close to each other, previous plant's tail water and the subsequent plant's reservoir have no height difference when the previous plant does not release water. It is noteworthy that there is always a height difference in previous plant's tail water and the subsequent plant's reservoir if one or both are dispatching water. According to a examined data, the subsequent reservoir level influences the tail water level of the previous plant by increasing or decreasing its tail water level. Thus, we can take the subsequent reservoir level into account when forecasting the tail water level of the previous hydro plant instead of considering that its tail water would only be dependent on the discharge of the plant.

There are also negative differences shown in Figure 31 but they are not realistic since negative difference would mean that the river flows backwards. Negative differences are caused by water movement in the river part between the plants when the discharge is stopped in both plants. It is also noteworthy that the tail water behavior varies depending on weather conditions since the difference increases more when the river has ice cover than during open water time as can be seen from Figure 31. This phenomena is caused by ice cover which narrows riverbed and thus the water movement is more restricted.

Because the hydro plants are strongly hydraulically coupled to each other, tail water behavior should be perhaps modelled so that if there is subsequent reservoir, it should be taken into account and hence the chosen method is congruent with presented in Figure 31. Hence in the studied river system, we use this method to all tail water levels except the hydro plant *P5*. The method does actually result very strong relation between previous plant discharge and difference in tail water and the subsequent reservoir. For example based on the same data which had been analyzed in Figure 31 (during the time of ice cover), the relation between the two variables have correlation coefficient of 0.965. In addition to high accuracy, the method takes partly the subsequent plant’s efficiency into consideration by including some of its head level losses into the model.

In reality, tail water behavior is not an immediate phenomenon. Thus, tail water level changes once hydro plant discharge is altered but the change is fully realized after a delay. Therefore, in reality the tail water level change should be smoothed. In intraday markets where production is bid in hourly basis without certain knowledge about next hours bid realization, it might be difficult to precisely model tail water behavior. It is easier to consider that one hour change in production does not influence on the sequential hour’s tail water level and therefore only estimate what is the tail water level on average during the operation hour. This assumption might need to be re-considered once the control center gets more knowledge about tail water dynamics related to this issue.

Intake losses obtained from statistical data have clearly smaller effect on the head losses than increasing of tail water. However, we found out that the losses between reservoir level measuring point and water level right after trash track are similar to the quadratic equation. This difference of height is presented in Figure 32.

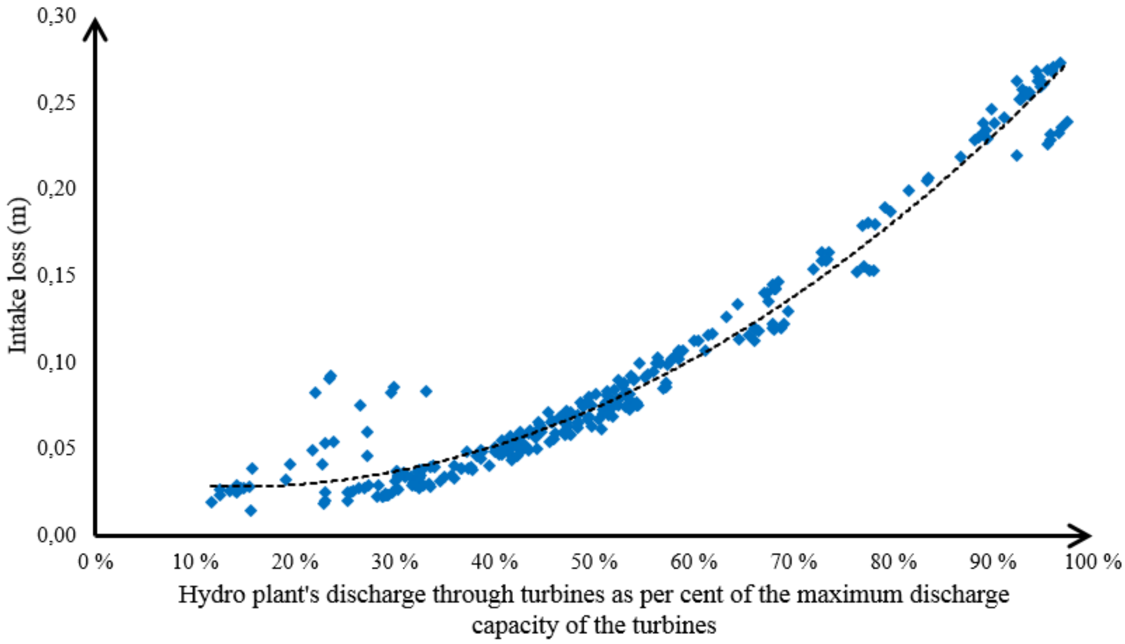

Figure 32. *Intake losses modelled as the height difference between reservoir level measuring point and water level right after trash track.*

As Figure 32 illustrates, there is strong relation between intake loss and plant's discharge. Once both intake and tail water losses have been modelled, the net head can be estimated

$$NH = h_{reservoir} - h_{tail\ water} - h_{intake\ losses}. \tag{13}$$

The net head (NH) estimation is needed in hourly basis. Estimated net head is known when bidding in the intraday markets due to available production plan which includes information about the planned discharge at a unit level but also forecasts for each water level related to the hydro plants. Therefore, it is possible to estimate how the efficiency of the production changes if production is altered from the original production plan by intraday re-scheduling or by realized balancing power bid. In reality there are also losses in a penstock but we assume that the losses in the penstock are included in the intake losses.

We decide that reservoir level influence on production marginal cost are taken into consideration with the hydro plants *P1* and *P5*. Other plants can be assumed to run with high reservoir level and thus we can assume that their losses are caused by the intake and tail water losses presented above. Reservoir level influence can be included to the modelling by combining hydrological balance (inflow, outflow and reservoir content) with one of the two methods presented in the chapter 4.3.1. Our assumption simplifies the model, but could result in good relation to actual hydrological situation for two reasons. Firstly, reservoir of the other plants are assumed to be on high level since they are operated as run-of-river plants. Secondly, the tail water modelling method that was presented in Figure 31 takes at least some of the losses in reservoir level into account if the reservoirs are not nearly full. Afterwards, there is possibility to include reservoir level to the model if the results seems to be inaccurate. This evaluation is not however included in this thesis.

4.3.4 Marginal water value of cascaded reservoir

This chapter presents the marginal water value in general terms. The theory behind marginal water value is covered but also considered the marginal water value of the river system. From economic point-of-view, hydro producers aim is to maximize water value by producing when it is most economically viable with as good efficiency as possible.

Marginal water value for plant reservoir r (λ_r) can simply presented as $€/m^3$ which implies how much reservoir's value (€) increase if one additional unit (m^3) is added to the reservoir (Skjelbred et al. 2017). Presumably it is available when bidding in intraday market, because production have been scheduled to meet day-ahead market obligation (Skjelbred et al. 2017) and as they argument, it might not be acceptable with a small-sized reservoirs like the studied hydro plants have. Hence it would be reasonable to consider if the marginal water value changing during the operation hour should be taken into account, especially when the plant's discharge is greatly larger than the inflow to the hydro plant's reservoir. This is not however treated in this thesis and moreover we assume that the marginal water values are known before bidding in intraday and balancing power markets.

Marginal water value in a cascaded water course normally increases when moving upward because more electricity can be produced with the same amount of water (Skjelbred et al. 2017). Thus the upmost reservoir's marginal water value is largest, and as a result of the previous sentence, water values at period t for the river in question can be presented

$$\lambda_{r1,t} > \lambda_{r2,t} > \lambda_{r3,t} > \lambda_{r4,t} > \lambda_{r5,t} > 0. \quad (14)$$

Marginal water value is depended on both the reservoir current content and also the future content. For instance, if there is no more capacity in a reservoir to use for storing water, all additional water must be released. This will decrease marginal water value. In order to be able price bids according to the marginal water value, there should be forecasts on how reservoirs in a cascaded hydro system will be changed if either one or multiple units' discharge is altered. If altering of one hour discharge forces to alter the subsequent plant's discharge in another hour, it should have effect on the marginal water value.

Operating cost for a plant mostly arises from used water during that period. This operating cost is actually same as water cost and it is the marginal water value difference between the plant s reservoir r and the immediate downstream reservoir $r+1$. (Skjelbred et al. 2017) Water cost ($€/m^3$) for plant s at time t can be presented

$$WC_{st} = \lambda_{r,t} - \lambda_{r+1,t}. \quad (15)$$

In some watercourses, there is only one hydro unit with one reservoir. That is, once water has been dispatched from the reservoir it becomes irrelevant to the hydro producer. (Kongelf & Overrein 2017) Thus the marginal water value is only based on the reservoir content and its opportunity to dispatch. This also applies to the hydro system's plant *P5* which releases its water to the sea. For this reason, marginal water value of the hydro plant *P5* is the smallest in the studied hydro chain.

Figure 33 presents how much energy is produced per one *HU* of water from each hydro plant with highest possible efficiency, i.e. with one working unit. These optimal discharge levels are quite close to each other with all hydro plants, which in turn allows them to dispatch with roughly same discharge without remarkable loss in efficiency. Figure 33 also shows how the cumulated water value of the hydro system decreases when moving downward towards the sea.

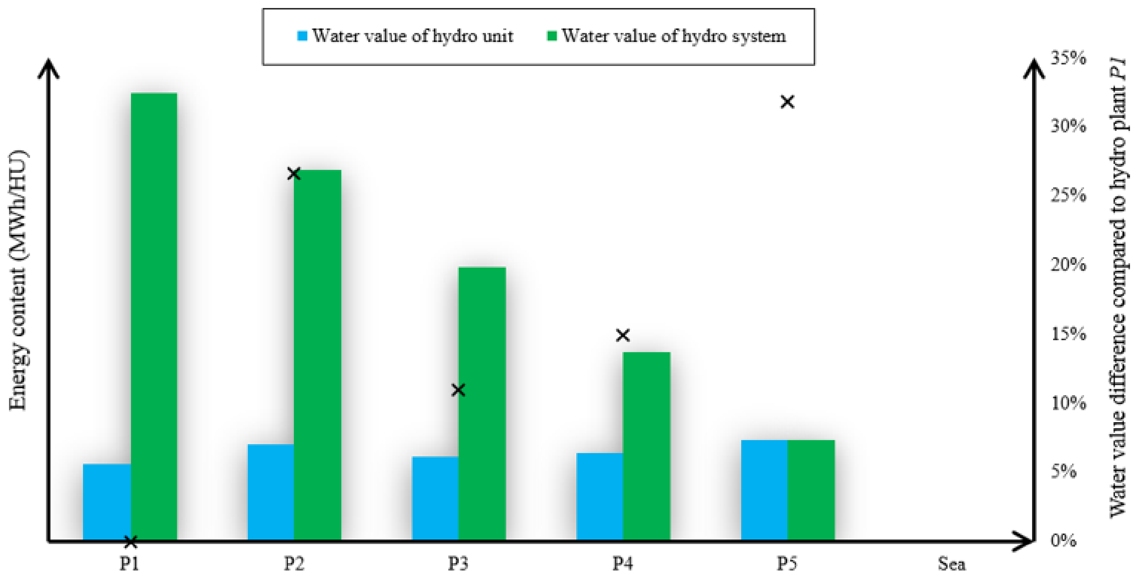

Figure 33. *Water values of each plant added with water value of hydro system as cumulated MWh/HU towards to sea. The ticks (percentage) are for comparison: it shows how much more one HU produces energy in subsequent plant's hydro unit than in the unit of P1.*

As Figure 33 above shows, energy received per one HU differs between the hydro units. If considering hydro units individually, energy received from hydro unit of plant *P5* with one *HU* of water is approximately 32 % higher than the corresponding energy received from hydro unit of *P1,* for instance (see the ticks in Fig. 33). The main reason behind this is the height of the head. *P1* have the smallest head and thus its ratio of energy per water discharged through turbine is smallest. On the other hand, water is most valuable in the reservoir *P1* as can be noticed from the water value of the hydro system in plant *P1.*

To summarize, marginal water value of the hydro plants is depended on day-ahead market results but since the reservoirs are relatively small-sized, hydro producer must notice price forecast of near future when bidding in intraday energy markets. Marginal water values are the basis for the marginal cost based bidding that is discussed next in the chapter 4.4.

4.4 Marginal cost analysis of the hydro plants

Starting point of intraday bidding is to conduct a marginal cost analysis for the all hydro plants in the river system. It's results can be used in support of decision making. This analysis will produce a bid curve which is often referred to as the marginal cost curve in Short-term Hydro Operation Planning model (SHOP) (Aasgård et al. 2016). The purpose of the marginal cost analysis is to create bid-curves that correspond marginal water value corrected with decreased efficiency for higher production levels. Considering a hydro unit with no other binding constraints, it is optimal to produce at best-point production level as soon as the electricity price is higher than the marginal water value of the plant. If the price increases beyond the marginal water value, increasing of production to above the best-point is trade-off between receiving higher electricity price and decreasing production efficiency. The trade-off depends on the discharge to energy conversion which again is depended on three-dimensional relationship between turbine efficiency, head level and discharge. (Aasgård et al. 2016).

We use marginal cost analysis in evaluation of the previously mentioned trade-off caused by the three-dimensional relationship. We assume that head level losses consist of both tail water and intake losses which were heuristically estimated for every hydro plant as presented in the chapter 4.3.3. In addition, we assume that reservoir levels are constant during one hour, and therefore the only head losses are the ones which were previously mentioned. This could be problematic approach but acceptable when developing the method. One can accommodate the model if the results seems to be inaccurate. Then based on the original working point and hydrological situation, such as reservoir level and tail water level, we calculate a hydro unit's production for different discharges with the mathematical formula that converts the measured head level and measured power into turbine's discharge. For a hydro unit, it is simpler to consider marginal cost that arises from increment of discharge unit than increment of energy unit, because it is much more easier to transform discharge to production than the other way round. (Skjelbred et al. 2017) Hence, in the calculation we increased the discharge with small increments and simultaneously estimated the head level based on the height losses related to each discharge level. As a result we get a transformation from unit discharge to production. An illustration of the transmission is presented in Figure 34. The curves are calculated with 1 m^3/s resolution in the discharge of the plant $P5$.

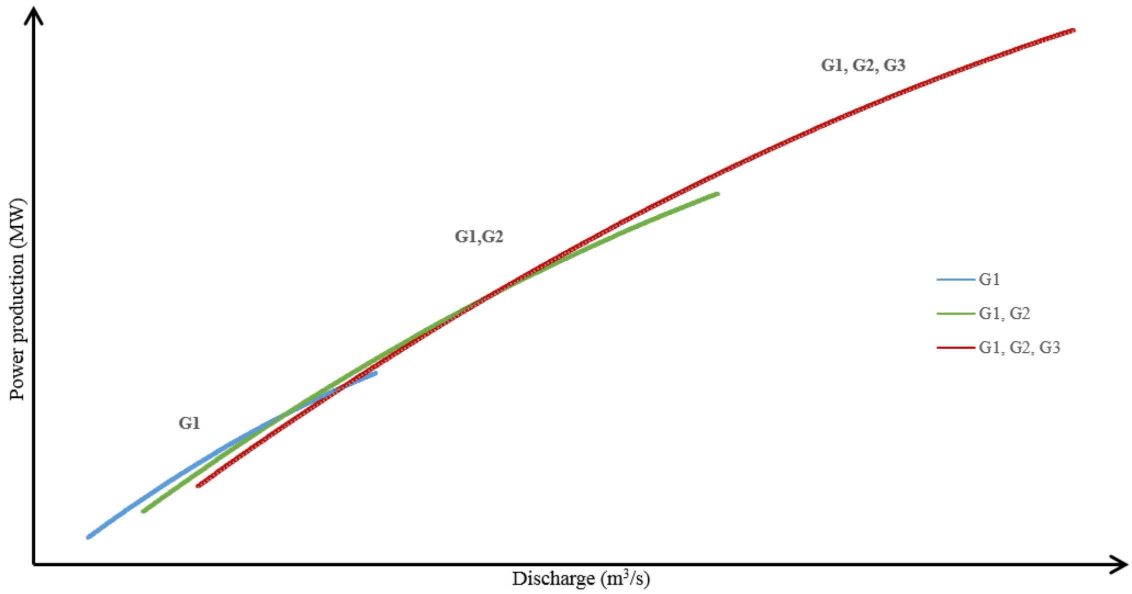

Figure 34. *Transformation from discharge to production in hydro plant P5. Turbines are assumed to be identical.*

Based on the discharge to production curves, we can estimate the marginal cost for the overall working range, i.e. minimum to maximum production. We can simplify the issue with heuristics proposed in Skjelbred et al. (2017). They suggests following four heuristics to produce bids with reasonable computing time:

1. Define the unit combinations
2. Define the operating points
3. Calculate average and marginal cost for each operating point
4. Determine the bidding points.

First two heuristics simplifies possible unit combinations and operation points by firstly assuming that hydro plants' generating units are identical if the turbines are same type and them are connected to same penstock as well as main tunnel and secondly assuming that the all units are running at same production level. The first heuristic basically proposes that if the hydro plant has three identical units, it means that the unit combinations can be reduced from eight different unit combinations to four unit combinations: from zero to three working units. For instance, when a hydro plant is dispatching with one unit, there is no reason to switch another unit on and stop the working unit. The second heuristic assumes that more optimal result will be achieved if all units are dispatching at the same level instead of operating at different levels. However, it only applies to Francis or Kaplan turbines because the heuristic requires that the power-discharge curve is convex. Therefore it does not coincide with Pelton turbine which power-discharge curve is normally nonconvex. As a result of the two heuristics, all operating points of the entire working area of the hydro plant are covered. (Skjelbred et al. 2017)

The third heuristic is used to define the average cost and marginal cost for each possible operating point of a hydro plant. The last heuristic is presented to select the best bidding points from the overall working range, taking into consideration the cost of deviation from the original production plan. (Skjelbred et al. 2017) One can see the theory behind the heuristics more precisely from the reference Skjelbred et al. (2017).

In (Skjelbred et al. 2017), bid curve, or supply curve, is assumed to be formed according to the economic theory in competitive market. The supply curve should be the portion of the marginal cost above its intersection with the average cost curve. This means that a producer is willing to produce only if the given production point's (p) average cost (ac_{cst}) is less than its marginal cost (mc_{cst})

$$ac_{cst}^{p} \leq mc_{cst}^{p}. \tag{16}$$

Otherwise, if the equation (16) does not hold true for a given production point, the optimal production point would be zero because lower marginal cost than average cost implies negative profits. (Skjelbred et al. 2017; Mas-Colell et al. 1995) In practice, hydro plant might have to release water hourly even if the equation (16) would not be satisfied due to for instance its permit conditions. In those circumstances, hydro plant tends to operate at the minimum possible production output to minimize its losses (Gebrekiros et al. 2013).

Hydro plant's average cost for a given operating point in a specific unit combination is the opportunity cost of the water used (Skjelbred et al. 2017). The hourly water cost is presented in equation (15) in chapter 4.3.4 and the transformation from the discharge to energy can be done with the discharge to production curve (see Fig. 34). Then the average cost can be calculated for the specific unit combination by estimating how much energy is received with each possible value of the unit discharge. Hence, the average cost (€/MWh) for specific operating point p in unit combination c in plant s in period t is (Skjelbred et al. 2017):

$$ac_{cst}^{p} = \frac{3600 \cdot WC_{st} \cdot \sum_{i \in I_c} q_{ist}^{p}}{\sum_{i \in i_c} mw_{ist}^{p}} \tag{17}$$
$$p \in P_{c,}, c \in C, s \in S. t \in T.$$

Where

C	Set of unit combinations,
I_c	Set of units in unit combination c,
P_c	Set of operating points in the unit combination c,
q_{ist}^{p}	Water flow through unit i in plant s in period t (m^3/s),
mw_{ist}^{p}	Power produced by unit i in plant s in period t (MW).

Marginal cost is the change in the opportunity cost that arises when the quantity produced increases with one unit. The marginal cost for one operating point is the change of opportunity cost of water involved as a result of a small increment in the discharge of the units. In the equation (18), it is expressed how marginal cost (€/MWh) for operating point p in unit combination c in unit s in period t can be defined. (Skjelbred et al. 2017)

$$mc_{cst}^{p} = \frac{3600 \cdot WC_{st} \cdot \sum_{i\in i_c}\left(q_{ist}^{p} + \Delta q_{ist}^{p}\right) - 3600 \cdot WC_{st} \cdot \sum_{i\in i_c} q_{ist}^{p}}{\sum_{i\in i_c}\left(\widetilde{mw}_{ist}^{p}\right) - \sum_{i\in i_c} mw_{ist}^{p}} \tag{18}$$

Where

Δq_{ist}^{p} A small increment in the discharge of unit (HU),

$\widetilde{mw}_{ist}^{p}$ Power produced when there is a small increment in the discharge of unit (MW).

Figure 35 shows average cost and marginal cost curves for the hydro plant *P5*. Prices of the curves are not shown due to confidentiality of the data.

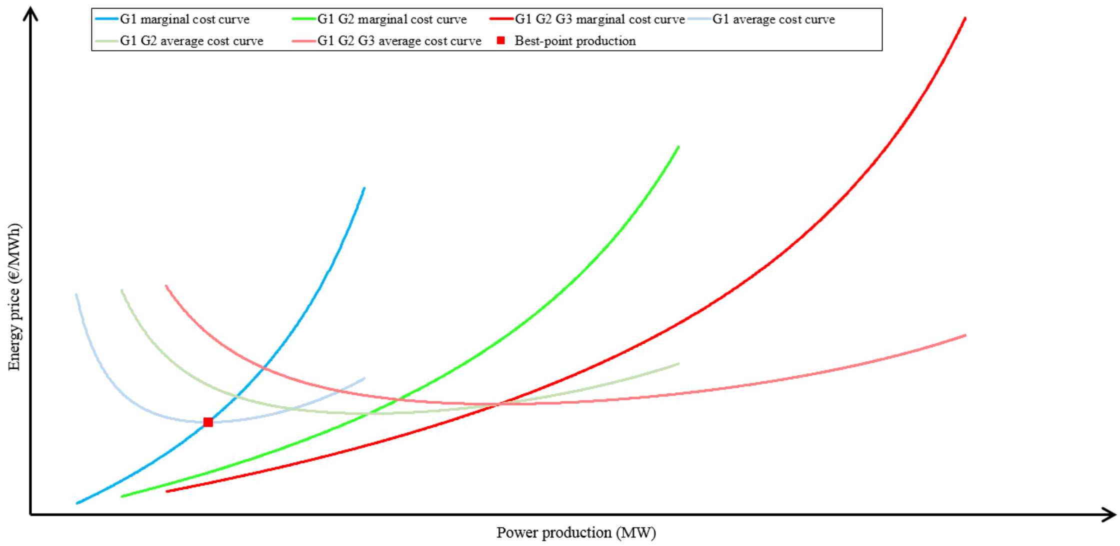

Figure 35. *Marginal cost pricing without considering start or stop costs for the hydro plant P5.*

Energy per volume of water is the highest at the power output of best-point production shown in Figure 35. Then marginal costs above and below this best-point production, are estimated based on their efficiency loss. Hence, we can use the marginal cost curves shown in Figure 35 when determining the prices related to each available production level.

At this point, the constraints for scheduling of the hydro production are not considered. We have just considered how a hydro unit efficiency affects the production pricing. Other hydro scheduling factors such as topology constraints, reservoir balances, unit-commitment decisions and end value of water should also be taken into account (Aasgård et al.

2016). These factors, with the exception of unit-commitment, are not elaborated further in this thesis. Unit-commitment decisions have direct influence on bid curves, their values and volumes but also on production efficiency. Therefore, they are elaborated further in this thesis. One can assume that topology constraints, reservoir balances and end value of water are given by the day-ahead optimization tool because they are related to marginal water value of reservoirs. Unit-commitment costs are related to hydro generator's start-up costs but also on difference in production efficiency of possible unit combinations. Therefore, one need to know which units are dispatched once a bid is accepted.

In real-word production bidding, the start-up costs cannot be neglected. According to a Swedish research paper (Nilsson & Sjelvgren 1997), the start-up costs arises from maintenance and loss of water. First, during the start-up, costs are caused by wear and tear of the windings due to temperature changes, wear and tear of mechanical equipment and water loss while turbine is accelerated and connected to the grid. Due the wear and tear of windings and mechanical equipment, it is assumed that the start-ups increases the need of maintenance and hence maintenance is performed more often. Secondly, when performing maintenance, unit is not available in power production and therefore water losses may occur: water might be lost (spillage) or water allocation possibility might be decreased. Last, occasionally during the start-up there is malfunctions in control equipment causing personnel costs (repairman) and unavailability costs. (Nilsson & Sjelvgren 1997)

As an exception, start-up costs can be neglected if a generator is planned to be started or stopped in the next hour. In those cases, producer has already done the decision to start or stop the generator and thus the deviation cost is included. On the other hand, accepted balancing power bids are uncertain with respect to duration of transaction. For this reason, producer has to consider more carefully its balancing power bids that will lead to a start or a stop of a generator. As have previously mentioned, it is advisable to run turbines in optimal production zones to receive as good water input per energy output ratio as possible. However, unit-commitment decision in intraday bidding is trade-off between start-up cost and better production efficiency. Thus hydro producer need to determine which unit combination is the most cost-efficient. The producer needs to determine whether it is more profitable to adjust generation with the working units than jump to new unit combination by switching units on or off (Skjelbred et al. 2017).

When we create a bid curve, we can ensure that the jump from one operating point (p) with the unit combination (c) to another operating point (p') with the another unit combination (c') is more profitable with following equation (Skjelbred et al. 2017):

$$
\begin{aligned}
&\left(mc_{cst}^{p} - ac_{cst}^{p}\right) \cdot \sum_{i \epsilon I_c} mw_{ist}^{p} - DC_{cst} \\
&\qquad\qquad < \left(mc_{c'st}^{p'} - ac_{c'st}^{p'}\right) \cdot \sum_{i \epsilon I_{c'}} mw_{ist}^{p'} - DC_{c'st}
\end{aligned}
\tag{19}
$$

$$p \in P_c, c \in C, p' \in P_{c'}, c' \in C, s \in S, t \in T.$$

Cost of deviation (DC_{cst}) from the original production plan for unit combination c in plant s in period t (€) arises only if production adjusting requires to switch units on or off. (Skjelbred et al. 2017). When consider the hydro system in question, an example of the trade-off can be following: Production in current operating point is utilized with one unit from each of the hydro plants giving total of five working units and the producer is willing to increase production in a way that the production is still in the production range of the working units. At some point, it is be more profitable to switch one or more units on than to adjust the production with the working units.

4.5 Adopting hydro system properties

Adoption of properties from previously unknown river system needs to be done carefully. Firstly, all persons that are related to the hydro production planning and operating must be familiar with the relevant features and constraints which are pointed out in the chapters 4.1 – 4.3.3. Secondly, operating and planning principles need to be adapted. For this, the importance of actual operating and planning experience should not be underestimated.

Next, there is an example how previously unknown river system's features can be trained to the responsible persons. Approximately six months was reserved for this purpose.

4.5.1 Constraints and features

Adoption of constraints and features was made in multiple steps. In first step, party C's personnel knowledge was increased by training material. This material that was shared to the personnel included topics such as description on the catchment area, prevailing water permits, hydro plant's features and actions in under exceptional circumstances. The main idea of the production of material was to gather all relevant practices and rules together. Before moving to the next phase, we produced a web query for the control room's personnel. With the query personnel could check if they have adapted basic knowledge about the river system.

Once all of the control center's personnel had some basic knowledge about the river system, the second step could be conducted. In the second phase, Party C had training sessions in where material topics were presented and discussed more precisely. In addition, the production planning tools and their working principle was introduced. Some of those training sessions were internal but there was also sessions were the Party A's expert was present.

In the last phase, Party A arranged an excursion for the Party C's personnel in the catchment area. The excursion was made during winter and included visiting at hydro plants and regulated reservoirs. A lot of useful knowledge was gathered during the excursion. Hence, the excursion was experienced to be really worthy in deepening of practical knowledge. For instance, based on experimental knowledge of river behavior, it was told what river parts are most challenging in forming of ice-cover. Or what are the challenges that might arise when ice-cover is melting and ice-cover breaks; how the ice blocks that move with river flow can be maneuvered trough flood gates as efficiently as possible and thus problems caused by moving ice blocks can be minimized. In addition, how these problems should be taken into account when planning production.

All gathered knowledge during the excursion was then updated in the training material. The same is valid with all new information and knowledge that are gathered during actual operating and planning. Updated material is then always easily accessible for the personnel who are responsible for the planning and operating of hydro production. This is crucial for the control center because there are also other tasks to be considered and therefore one need to have fast access to the relevant information.

4.5.2 Planning and operating

Before the physical production planning and operating was taken over, Party C had the possibility to operate the hydro plants and regulating gates based on the plans of the previous energy control room which was responsible of the river systems' all physical trading activities until the actual transfer of responsibilities. During this time period of six weeks, both previous and the new control room had the possibility to control the river system but the responsibility was still in the hands of the previous control room.

Main purpose for this arrangement was in giving of actual operating experience for the control center's Intraday Traders. Control center and previous control room made cooperation in production operating but all of the commercial planning and bidding was in responsibility of the previous control room. Basically, Intraday Trader altered the river's production based on the given production plan and was allowed to co-operate with the personnel of the previous control room. Hence, Intraday Trader could ask questions about the production operating from a person who had a lot of actual planning and operating experience. All of the control center's Intraday Traders had some working days in which they were purely allowed to concentrate on learning of the river system's operating and planning. This was enabled with providing another Intraday Trader to control room who took care of the normal duties of the intraday trading. During the time, Intraday Traders had also time to learn to use all of the tools made for the river system planning such as a reservoir level forecasting tool.

4.6 Background for intraday hydro activities

In the intraday activities of the river system, the availability of production is known with respect to production capacity, inflow and other market obligations. The main uncertainty is related to prices in different market places such as intraday and balancing power markets. Moreover it is considered that at least the next day's day-ahead market price forecast should be also considered because the reservoirs are relatively small sized. In addition to price uncertainty, the inflow of *P1* or *P4* might occasionally cause some uncertainty to production scheduling and valuing of available water on the reservoirs.

According to a prevailing practice, first and last hydro plants reservoirs in the chain are used in hourly production allocation. Plants between them are mainly planned as run-of-river production in a way that their reservoirs are close to their upper reservoir limit since their reservoirs are relatively small-sized. Hence, they are sensitive to forecast errors which causes great importance to the model accuracy since a minor error in the model could lead to profit losses if the actual situation differs from forecasted. Furthermore, according to Intraday Traders who are in responsible of actual operating of plants, manual operating of the river system is easier when hydro plants *P2*, *P3* and *P4* are operated as run-of-river plants. Intraday Traders are still getting more and more experience of manual operating of hydro plants in this particular river and thus it might be difficult to perceive how water levels behave in different circumstances. Hence, in this thesis, their potential is not considered in to a same extent than the reservoirs *P1* and *P5*. Because the day-ahead result are in great importance, next its planning process and background is described.

4.6.1 Day-ahead phase

The river's production is planned and bid daily to the day-ahead market at least insomuch that water permits are not infringed. This means that minimum production sold on the day-ahead market is always forecasted to be enough to prevent or minimize spillage of the hydro system. In addition, day-ahead bidding considers price uncertainty to some extent by price dependency of bidding. Currently besides the day-ahead market, bidding considers also frequency containment reserves (FCR). As mentioned, other markets have not been taken into account when generating optimal bid. So, the control center will always bid the main volume to the day-ahead market without considering any other energy trading possibilities on intraday or balancing power markets. As (Vardanyan et al. 2013) argues, it is reasonable for hydro producer to bid base amount to the day-ahead market even if producer utilizes coordinated bidding, because day-ahead sales are definite by nature. The day-ahead market has much more liquidity than other energy markets. For instance, in year 2017, the total traded volume on the Nordic-Baltic day-ahead market was 394 TWh, while the intraday markets' turnover was 6,7 TWh including traded volumes from Nordic, Baltic and Germany (Nord pool 2017a). They also underline the uncertainty of the balancing power market. Producer cannot be sure how much energy it sells on the balancing power market and hence there is high risk of spillage if up-regulation bids are not activated and reservoir capacities are small. (Vardanyan et al. 2013)

The river production plans are made with a optimization framework which is included in the control center's Energy Management System. The framework have been developed before actual taking over for the purpose of testing and further development. Basically optimization model gives results of every units discharge with one hours resolution. Once discharges have been decided, another optimization level creates generator-specific production plans. After the optimization result is given, a person responsible for trading may alter it manually, for instance in order to smoothen production for successive hours or to prevent one hour stoppage of hydro unit. Even though optimization is done for next day-ahead period, used model seeks to find optimal production of longer period, i.e. time period of several days, by maximizing incomes from day-ahead and frequency containment reserve markets. Physical Trader can restrict the optimization model by giving discharge level or giving target water levels for the model. Currently optimization runs automatically once in every hour or it can be manually activated. This automatic optimization seeks to find optimal production plan from next available trading hour to the end of optimization period. Hence optimization tool can be used in intraday production planning when inputs like realized water levels and intraday market trades have been updated to the EMS. A drawback in this optimization is that it is blind to the market situation in intraday market. Thus it might suggest change to the production plan regardless of the economic impact that is resulted when the trade is carried out in the intraday market. One outcome of this thesis is to increase automated monitoring of intraday market in order to find feasible bids in the marketplace but also estimate intraday prices for increase and decrease of production. The calculation is already available in the EMS and therefore it can be used in the production optimization in the future.

Both physical characteristics of the river and hydro plants are modelled to the optimization tools. Optimization method is Mixed Integer Linear Programming (MILP) which solves production without considering any uncertainty rising from market price or inflow. In order to find an optimal production, this MILP optimization tool uses linearized models for hydro unit features such as piecewise linearized production curves. In addition, the model includes variables that are restricted to have integer values. Planning deals with complex and nonlinear relations between different hydropower features. Using of these linear and integer variables is one way to tackle those nonlinearities.

As mentioned, physical characteristics of the hydro system are modelled in the optimization tool. In practice this means that optimization can hourly alter every plants inflow with relation to outflow if it can increase water value of the hydro chain. In reality, reservoir usage of plants *P2*, *P3* and *P4* is restricted because of earlier described reasons. Thus, the main idea of optimization and planning of the river production is that the production plan should be in reality feasible. Therefore, the optimization of reservoir levels is restricted, i.e. the profit is not necessarily maximized with aggressive regulation of each reservoirs because it could lead to non-practicable production plans because the production is operated manually. Perhaps in later steps, reservoir usage could be reconsidered once the Intraday Traders have more knowledge about the river behavior or the automation level of production operating is increased. Therefore, as mentioned in the chapter 3.3.1, the lack of knowledge about river behavior could have a decreasing effect on production flexibility because of Intraday Trader might be too precaution with safety margins related to permit levels. Hence, it is reasonable to expect that value added with intraday trading will increase when not only personnel knowledge of water movement improves but also optimization tools are developed further.

4.6.2 Intraday phase

There are many features and constraints added with uncertainty of future inflow and prices behind hydro bidding problem that should be adapted in the optimization tools but moreover in the Intraday bidding tools. Basically, intraday bidding limitations arises from both technical and hydrological constraints. Based on these limitations and forecasted water availability and market prices, control center need to consider following issues.

Firstly, to be able generate bids to the intraday and balancing power markets, hydro producer need to be able to answer how much energy can be provided and at what price? When operating in intraday markets, producer knows its original production plan and thus its available trading capacity. Then it decides at with price it can generate more energy or willing to produce less energy, respectively.

Secondly, how the sequential hours should be linked to the bidding? Given the fact of the river system's small sized reservoirs and nearly run-of-river production, the bidding in one hour is not decoupled in time. Basically in this thesis this means that the sequential hour's production efficiency is either increased or decreased based on the water balance change that is caused by one hour production altering. Next and last issue is also linked to the sequential hours.

Finally, the available energy content in reservoirs need to be known in hourly basis for the whole reference period in order to make bids that are practically and economically feasible. This means that altering of one hour's production should be done within given reservoir volume without running in to unavoidable production imbalance caused by the maintaining of water level rights. In addition, reservoir contents in sequential hour need to be considered. For example, an undesirable situation for hydro producer is to save energy to the reservoir by buying from intraday market or down-regulating and then run to a situation where it is forced to sell production at any positive price or even spill the saved water to be able manage water permits of the reservoir. For this reason, the forecast tools are in the great importance when generating bids. Based on the forecasts, hydro producer determines water value of each reservoir.

5. INTRADAY ACTIVITIES

This section describes the basis for performing intraday activities. Unlike daily planning and bidding hydro production in the day-ahead market, intraday activities are performed continuously. All trading activities and hydro dispatching are executed from the control center's control room. The control center's tasks are roughly divided as follow: one person at a time carries out daily day-ahead planning and bidding and one person at a time is responsible for intraday trading and real-time hydro operating by working in shift. In addition to those duties, Physical Traders, whose are responsible for day-ahead trading, performs short- and mid-term planning of hydro assets.

5.1 Intraday bidding premise and process

In this thesis, intraday bidding is composed of the intraday and balancing power markets. These markets are for energy trading while there is also some discussion on reserve markets which are based mainly on capacity trading. The sequential clearing of different markets is presented in Figure 36.

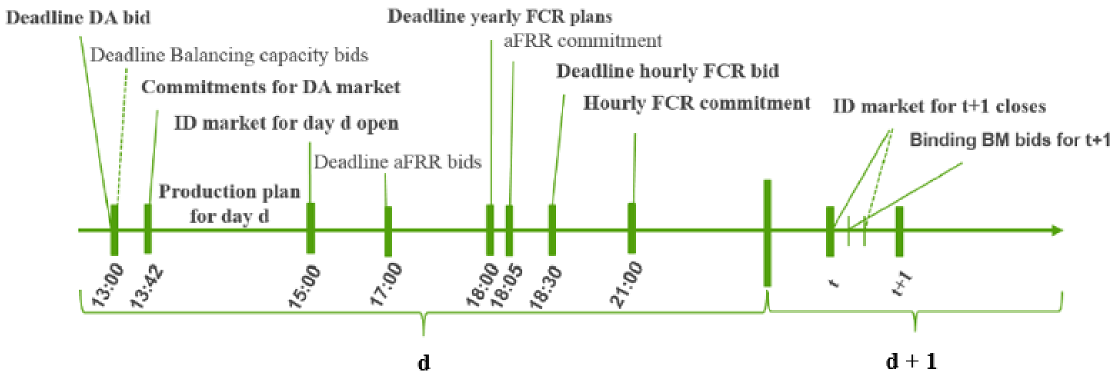

Figure 36. *The sequential clearing of different market places. Bolded markets are traded every day. The rest are traded if TSO decides so. Deadline of balancing capacity bids is only valid if producer is entered in this market. Timeline is in the Eastern European Time.*

As the timeline shows, some of the trading opportunities are mutually excluded and hence commitment in one market will decrease possibilities in the other market. In addition, one can notice that there are time periods when producer cannot use its all available capacity in the intraday market if it has bid in the reserve markets because those results are not known until the clearing time and hence producer will not know its commitments. Once hourly FCR commitment is cleared, producer knows how much it has production capacity available for the next day's $(d + 1)$ intraday and balancing power markets. This is though true only if the producer has bid on hourly FCR market.

Since there are multiple market places where hydro production can be bid, it is be imperative for hydro producers to obtain bidding strategy for each possible market. Ideally, hydro producer should consider its bidding strategy in all markets as a joint problem because the product in all markets is either the same or at least linked so that the accepted bid in one market reduces possibilities in others (Aasgård et al. 2018).

5.1.1 Background

Hydro system planning and trading is continuous and demanding task which needs to be performed every day. The day-ahead obligation of hydro producer basically sets the basis for the sequential markets shown in Figure 36. For instance, the obligation usually determines if a generator is on or off. If the generator is not spinning, it cannot provide reserves in FCR-N, FCR-D nor aFRR markets. Furthermore, the day-ahead market represent the main part of energy trading income at least in the river system in the question. Therefore, it is extremely important that day-ahead commitment reflects marginal water value well and moreover the production plan is feasible. However, in uncertainties of market price and inflow, there might be hours in which the day-ahead commitment is undesirable in the eyes of the hydro producer. Those hours might require trading in intraday market which price can differ from the hour’s day-ahead price quite considerably because of its lower liquidity.

Incorrectly evaluated water value in the day-ahead bidding phase could be limiting factor in the intraday and balancing power markets. The previous sentence might be explained by simple example of random forecast error given by (Klaboe & Fosso 2013): considering two hydro producers who have identical production portfolio and they bid for a specific hour in the day-ahead market. In hydro production case, their marginal cost is the future opportunity cost and therefore the bid curves in the day-ahead market are highly dependent on forecasts for prices and inflow. Assume that for this specific case, one of the producers (producer A) has no random forecast error, whereas the another (producer B) wrongly anticipates one or both of the higher future inflow and lower market prices. In this specific case, this would mean that the producer B commits in the day-ahead market to produce at its full capacity while the producer A have capacity to use in the intraday market. (Klaboe & Fosso 2013)

Apart from day-ahead market, some of the studied hydro units’ capacity is offered to different reserve markets, and then the rest of the capacity is available in energy trading markets. These markets are presented in Figure 36. This thesis focuses mainly on hourly markets i.e. intraday and balancing power markets which are cleared during the operation day.

During operation day, hydro producer receives information about realized market prices, inflows and realized reservoir levels and makes trading decisions such as trade in the intraday market. When producer receives new information or makes a trading decision, it should consider what is the impact on nearest future hours production and trading possibilities. In a hydro system which have relatively small-sized plant reservoirs, decisions impact must be estimated in order to bid economically. Hence, the intraday bidding has to take both new information and decisions made into account when valuing available water in the reservoirs. This valuation should be reflected to reservoirs' marginal water value and thus the marginal cost curves calculated for the river system's hydro units.

Hence, marginal cost curves are influenced by this previously descripted stage-wise information and decision flow. Those stages could be included in determining of marginal water value in reservoirs with a decision tree. This approach to the stage-wise problem is used in the previous literature. A simplified illustration of decision tree is presented in Figure 37. Model of decision tree is adapted from a master thesis (Kongelf & Overrein 2017) that examines coordinated multimarket bidding from a hydro producer perspective.

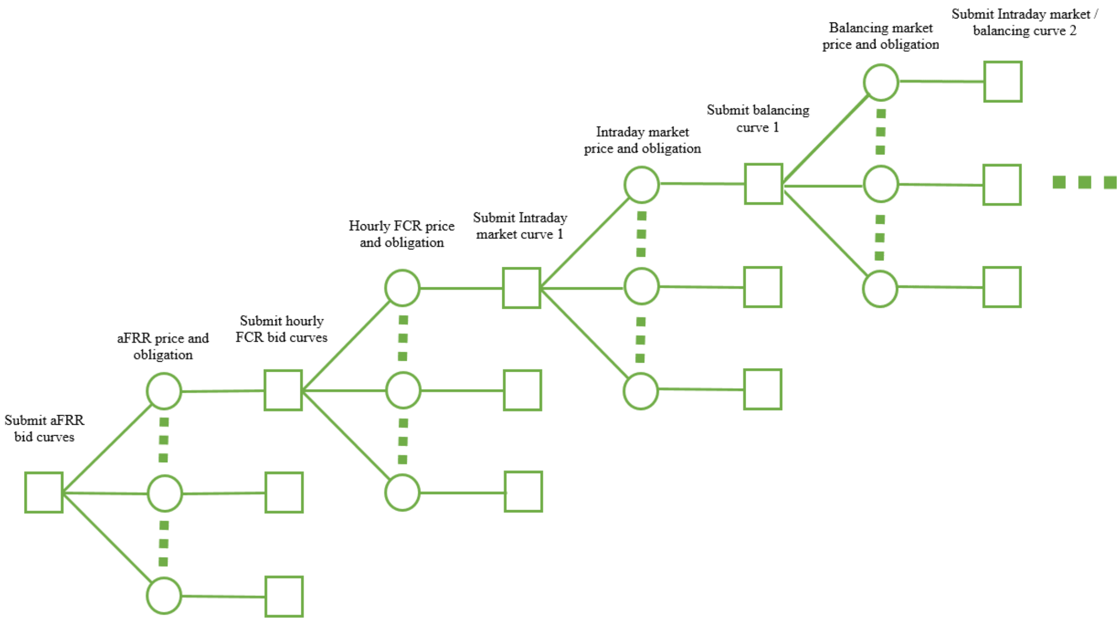

Figure 37. *Decision tree based on markets that are currently cleared after the day-ahead market. Squares denote decision and circles denote new information. (Kongelf & Overrein 2017)*

It should be noticed that the presented structure of the decision tree is not important. Its purpose however, is to underline that every time a hydro producer receives new information, it should consider how the information influences on the following stages. The idea is following. Considering period from operation day (d) to next day-ahead period ($d + 1$). During hours 01:00 – 13:00 EET, producer can estimate water value of the operation day d based on the day-ahead commitment and possibilities in intraday markets but also becoming day-ahead period because before leaving the final day-ahead bid, it is possible to re-consider $d + 1$ energy production. This means that producer might be able to increase its profits by using it unused flexibility in intraday market and balancing power markets in the day d. Moreover, if the next day's ($d + 1$) production plan uses reservoirs aggressively, a producer might be willing to fulfill the reservoirs during the operation day or in the night-time in order to be able meet the target reservoir content in the beginning of the next day ($d + 1$). On the other hand, trades that increase realized production such as up-regulation trades in previous stages, could influence to producer willingness to buy energy back in the markets, or similarly use extra water by trading in the markets if production is saved during the operation day. Therefore the bids in the latter hours might be reconsidered.

5.1.2 Bidding

Even if the latest trend in hydro bidding strategies have been to move towards coordinated bidding, there are, however, not many papers that deal with real-time balancing power or intraday markets bidding strategies individually. Strategies and methods for those markets are perhaps included in the coordinated bidding modelling but they are not necessarily specifically presented. In the papers, bidding is based on marginal cost pricing but the uncertainties that effect on pricing might not be considered in details. Moreover, reservoir levels and water values are often considered to be constant during one hour or even one day. These could be problematic assumptions when bidding nearly run-of-river hydro production.

Interest towards coordinated bidding has grown because it is assumed that the need for reserve power is increasing when the share of renewable power is increasing (Fodstad et al. 2018). Several authors have used optimization models to investigate whether coordinated bidding in multiple markets increase possible gains in relation to only consider day-ahead price scenarios. For instance, Kongelf and Overrein (2017) investigated coordinated bidding that takes the alternatives of daily normal operations reserves (FCR-N) and balancing power market into account when bidding in the day-ahead market. They used a stochastic mixed integer programming in modelling of power market bidding and the operation of hydropower capacity and considered the market conditions of the price-area NO3 in Norway. In their model, maximum balancing market share is set to 15 % of the total market transaction. They argue that it might be an overly restrictive constraint and result that the value of balancing market are slightly underestimated. They reported that producer could achieve 1 % gains when coordinated bidding is utilized in one watercourse system with one reservoir and generator, and the gain decreases to about 0.5 % when planning for more watercourses simultaneously. The authors argue that the decreasing is caused likely by increasing amount of generators when moving from one watercourse to multiple watercourses. In such circumstances, producer can simply reallocate it production to respond to reserve and balancing market opportunities.

Given the structure of the intraday and balancing power markets demands hydro producer to be able quickly submit bids or accept offers. In the literature, Skjelbred et al. (2017) introduced a method for hydro producer to create bid curves for these market places. The proposed method can be used to calculate marginal cost for bid points covering the entire working area of a hydro unit including all the physical limitations, deviation costs arising from start and stop of unit and possible reserve obligation in other markets. Their method was implemented to some extent in this thesis (see chapter 4.4).

5.1.3 Hydro system's flexibility in intraday trading

In the phase where the actual operating experience has not been gathered throughout the different seasonal periods, the constraining effect of organizational factors are hard to estimate. Other flexibility factors are easier to estimate. In the studied hydro system, the most important factors to be consider are water availability and hourly production allocation. Both of them are depended on the water balance situation, production capacity in respect to the inflow and water permit. The available flexibility need to be reflected into the valuing of water.

Firstly, in the studied hydro system, available energy production capacity is highly depended on the inflow to the reservoirs of units *P1*, *P4* and *P5*. With described hydro system properties, the energy content in hydro units *P1* and *P5* are easiest to use in daily production allocation. In addition, the inflow to the hydro unit *P4* can be seen limiting factor because its inflow is typically higher than the previous units due to a side-stream. This additional inflow from the side-stream to the hydro unit *P4* can be restricting factor in two ways.

When the inflow is high enough, hydro unit stoppage during night-time might be problematic in practice because hydro plant's *P4* water permit is linked to the river part where storing capacity factor is small. The vicinity of plant *P4* is presented earlier in Figure 29. Thus, in situations when the inflow to the first hydro unit does not set limit to hydro units stoppage during the period of low demand, the hydro unit *P4* might be forced to discharge due to the side-stream. In those circumstances, hydro unit *P5* is not however forced to produce if there is enough room in its reservoir.

Additionally, because *P4*'s discharge capacity is roughly same as with the previous units, the side-stream flow might set limitation to discharging of previous units. Otherwise, producer might be forced to spill water through the spillways of *P4.* In those circumstances, producer need to consider carefully whether it is acceptable in river system point of view or beneficial to system overall profitability to spill water with one hydro unit *P4* when increasing the flexibility of the rest of the hydro units. These two possible situations emphasizes the need for accurate forecast of the side-stream flow but also underline the importance for evaluation of the side-stream flow during the operation day.

The river's production is highly depended on the inflow to the reservoirs. Its available daily energy for production is constrained by the amount of inflow to the reservoirs *P1* and *P4* added with the available reservoir content in reservoirs *P1* and *P5* in the beginning of the day. On the other hand, production must be always at least as the water permit requires or as much that is needed to maintain water balance i.e. prevent spillage. This is apparent in both extreme cases of low and high discharge compared to the relevant hydro unit discharge capacity. In dry circumstances, reservoirs are hard to fill if they are used. Additionally, production is impossible to allocate in an hourly manner when the inflow is close to the maximum available discharge capacity. In those circumstances, the uncertainty of near future prices and inflows are dominating and thus flexibility utilization is hard to do in a way that the profits are really increased. For instance, with high inflows or flood, producer have to deal with the uncertainty of the inflow: when the inflow will actually exceeds the unit discharge? In same way, when the flood is decreasing, does the change in inflow be “stationary” or will the inflow rapidly increase after short declining? In Figure 38, there is presented different daily values for the discharge of the hydro plant *P1*.

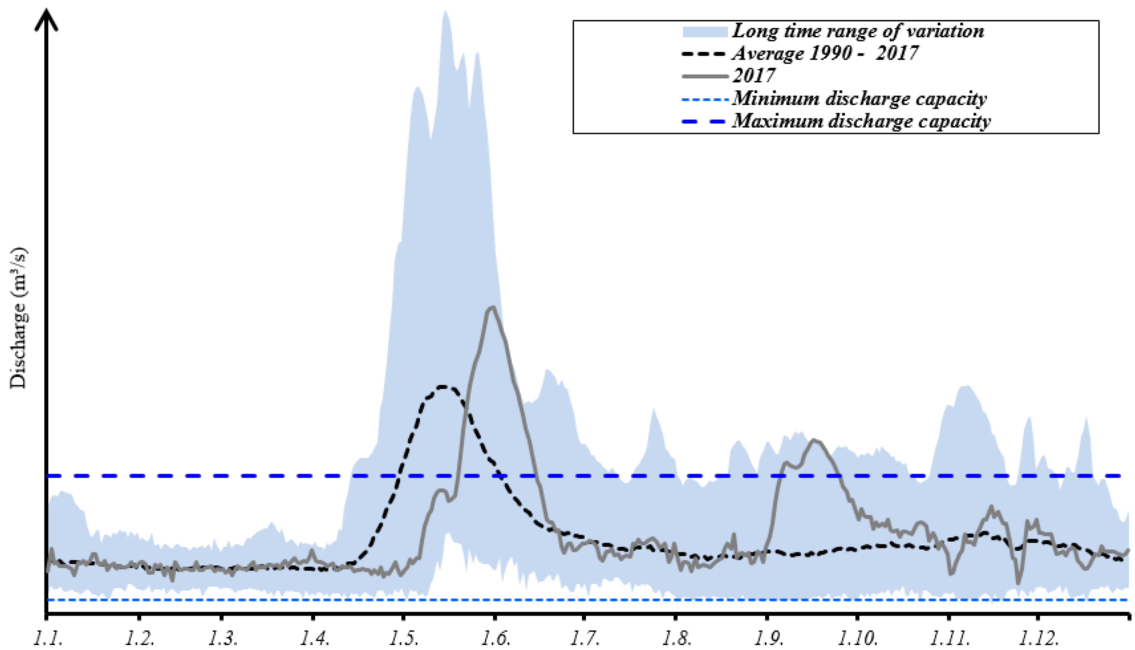

Figure 38. *An illustration of the hydro plant P1 daily average discharge with relation to the turbines’ discharge capacity.*

We can see from Figure 38 that the discharge capacity is good in relation to inflow except the time of spring flood. Hence, this basically enables in daily basis to meet the highest demand with higher power production and minimize production during night-time.

Water permit does require minimum average daily discharge but it is not forbidden to stop hydro units. This can be advantageous in production allocation because production can be scheduled to the day-time when the demand is higher. This enables that especially the hydro plant *P1* reservoir can be filled more easily during lower demand by stopping of the discharge. For the same reason, hydro plant *P5*’s reservoir can be used in a more price-depended way. However, the stoppage of hydro units is not considered to be an option if hydro unit is online to maintain reserves. Only water permits are prioritized over providing the reserve commitment. Thus when the unit is providing frequency containment reserves, it need to be taken into consideration as a binding limiting factor when bidding in the intraday markets.

Hourly production allocation is limited with the physics of water movement in the river basin. The question is how the prevailing reservoir content can be used with different water balance. For instance, because of water balance of reservoirs, it is not realistic that the river production could be zero at the next hour when the reservoirs are nearly full and the discharge in the previous hour is high. Even if it would be possible, high and rapid variations in discharge could attack the river bed and therefore they are not environmentally desirable.

From water balance and estimated reservoir content, it is possibly to evaluate the maximum hourly change for production. In the river where the delays are short (tens of minutes), the production can in practice be adjusted during operation hour and thereby the potential for production allocation between two successive hours can be higher. For instance, if the reservoirs of *P1* and *P5* water balance physically enables it, they can be used in rapid production decrease even if the other reservoirs are full. Then, other plants' power output can be decreased in steps after a delay.

Available reservoir can be utilized by trading in intraday markets if economically profitable. Since given hydro system properties, the energy content in hydro units *P1* and *P5* were considered more precisely in order to be able answer how much energy can be traded. In practice, energy accessibility can be evaluated from flexibility that was unused in day-ahead market. As a result of day-ahead market, there is hourly units' reservoir usage plans that can be used in the estimation. These plans, combined with knowledge of reservoirs' water volume as a function of a reservoir level are then used in the estimation of the accessible reservoir volume in Hour Unit. Hence, exploitable energy for every reservoir level can be estimated with equation (9) based on their water content in a way that water released or saved is within the water permits. As a result, available energy (E^r) in reservoir in time period (T) for both buy and sell can be presented in unit $\mathrm{MWh/HU}$.

If a reservoir is used with its full capacity available in day-ahead market, i.e. reservoir is filled and drained once within day-ahead market period, there is no possibility to sell or buy energy without absolute necessity to compensate the same amount of water within the period. This might be problematic if producer is willing to utilize attractive market prices in intraday or balancing power markets. An illustration of reservoir hourly energy allocation is shown in Figure 39.

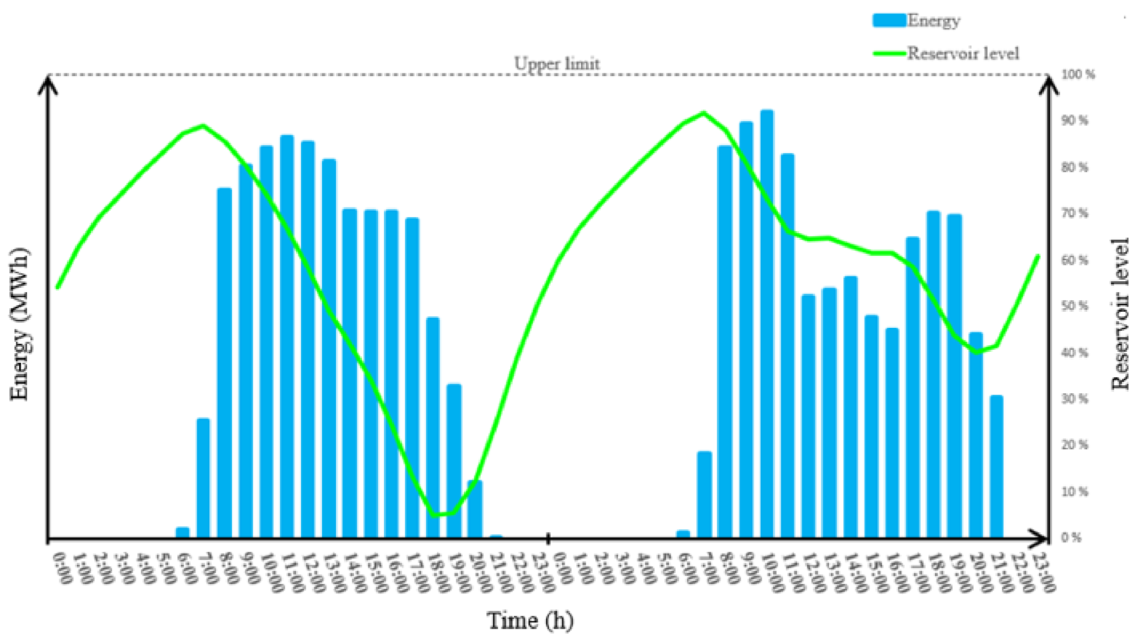

Figure 39. *An example of two successive days: Day-ahead market water usage of a hydro plant with one reservoir. Reservoir level scale is based on the allowed lower and upper limits of the plant reservoir.*

From Figure 39 we can draw a conclusion that original plan of the reservoir level must be noticed when generating bids in the intraday and balancing power markets. Considering the shown example of Figure 39 with an assumption that there is available production capacity left in each hour. When available production capacity is used in markets during morning hours of the first day, producer is forced to buy the needed energy from the intraday or balancing power markets. On the other hand, if energy is bought from the markets during the first day's hours, producer might be forced to sell roughly the same amount of energy during the subsequent hours. Hence, it was decided that considering of one day-ahead period is not practically acceptable when evaluating of available energy in reservoir because it might mean that possibilities in the markets are missed. Therefore, the shorter period is needed with some insight of the relevant market places. Insight could be achieved based on the intraday market demand and supply situation. This is illustrated later in chapter 5.3.2.

If energy allocation is more like the second day of Figure 39, i.e. not as aggressive as the first day, producer might use its available additional production capacity in trading without the absolute necessity to buy energy within the same day-ahead period if it is more profitable to fill the reservoir up later. For instance, if the operation day's intraday market prices are more attractive than tomorrow's forecasted day-ahead prices, producer might be willing to use extra water during the operation day and compensate the used water by producing less tomorrow. In the day-ahead bid planning, Physical Trader evaluates how much water can be used tomorrow. Typically, day-ahead optimization uses target reservoir levels as an input of the planning, such as reservoir content in the beginning of the day-ahead period. Therefore after the closing of the day-ahead market, producer cannot change its tomorrow's bid. If water balance situation in reservoir is changed from the original plan by trading in the intraday markets before dead line of next day's day-ahead bid submit, producer can take this into account when leaving the hourly production bid and therefore minimize its financial risk in the next day's intraday markets.

5.2 Operating of hydropower

The river system is operated according to its total production plan. Basically, producer schedules hourly production plan for each generators based on obligations in energy and reserve markets but the generators can be adjusted from the original plans if it does not violate any of reserve capacity obligations nor environmental contracts. This means that the producer has more flexibility in its production. When considering a hydro unit with one reservoir and a need for production re-scheduling due to change in inflow or production availability, for instance. The party responsible of the hydro unit has no other change than trade in the intraday market or accept that the imbalance is exposed to price risk of balancing power price. In contrast to one hydro unit case, hydro system with many reservoir can be utilized to meet original obligation even if the plan of one or more of the units must be re-scheduled. This could be economically reasonable if the intraday market's supply and demand situation is not favorable for trading. If the production of the river system cannot be bend physically to the original plan, the trading must be carried out in order to meet the obligation.

Re-scheduling of the river's production can be done with the same optimization tool that is used in day-ahead planning. Intraday Trader can also use reservoir level forecast tool as assistance when considering how production should be re-scheduled. Production plan or forecast for short-term horizon is calculated and presented in EMS. An example of visualized presentation of production schedule is shown in Figure 40.

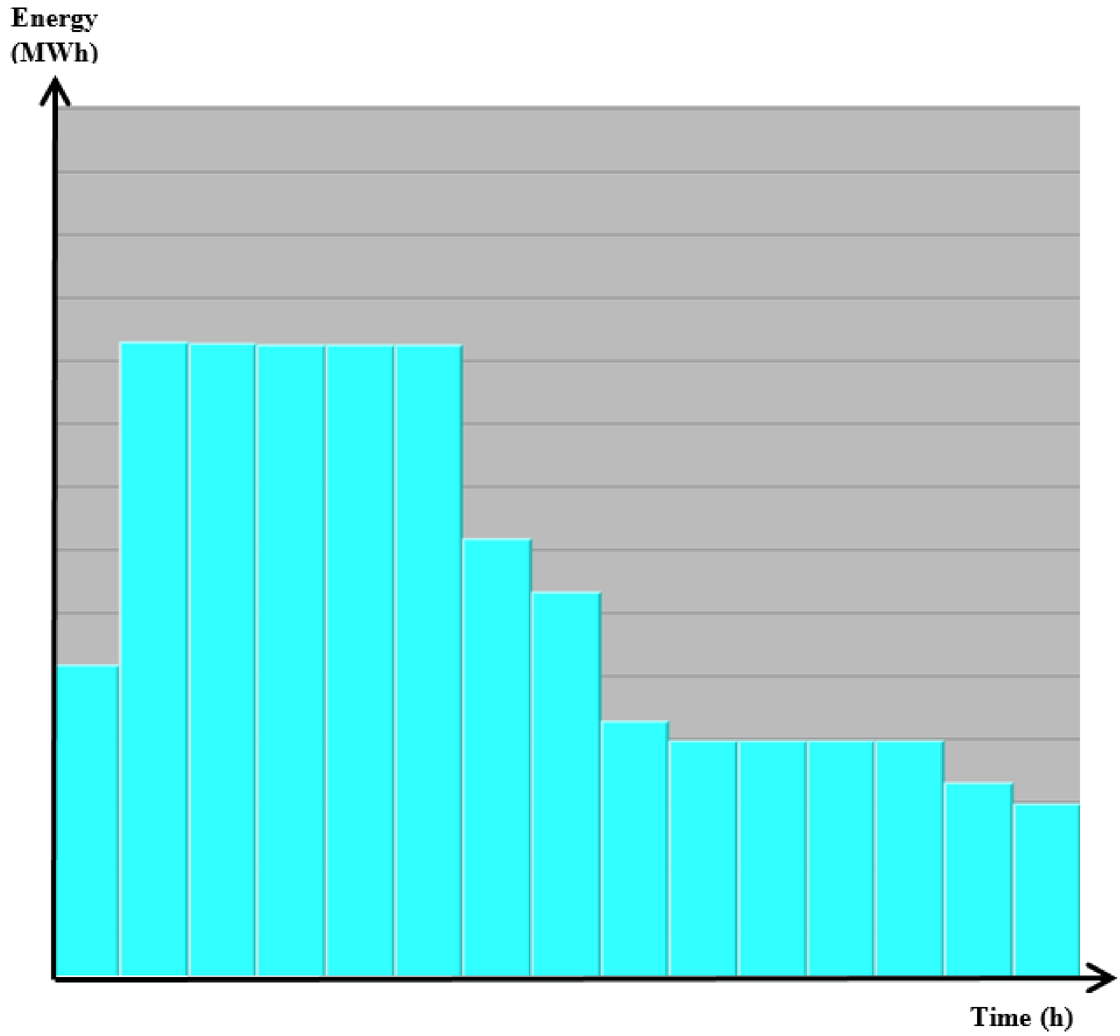

Figure 40. *Visual presentation of hourly forecasted production in EMS.*

Production plan is converted to planned hourly reservoir level for each plant's reservoir. Optimization tool used in the day-ahead planning uses the latest reservoir level forecast available. As default, the optimization of the river system runs once in an hour automatically, reproducing new forecasts for each reservoir level and changes production plan of the river if unit permits are forecasted to be infringed. From planned reservoir usage, it is possible calculate how much energy can be produced or bought from the intraday or balancing power markets within allowed reservoir level limits. This forecast of available energy added with market price point of view, are in vital role when considering how Intraday Trader can maximize profitably of hydro production or minimize income losses caused by some unseen event or force of circumstances.

Production optimization tool provides support for intraday planning of production. For instance, it can automatically provide new production plan for hours of realized intraday market trade. However, currently there is no tool available for scheduling of production once a balancing power bid is activated. In the future there could be a need for a such tool. On the other hand if the balancing power bids are based on the marginal cost curves considered in this thesis, they should reflect the current hydrological situation and operation point and therefore the bid could be realized as it is modelled in the bidding.

5.3 Intraday value creation

In this thesis, we assume that marginal water values for every reservoir are known based on short-term planning. This means that target reservoir content and end value of reservoirs are known at the end of the period and therefore them are not treated in this theses.

Additional value can be created by actively participating in intraday and balancing power markets. In those markets, bidding is done in hourly resolution. Hydro bidding is restricted by following boundary conditions related to hydro plant s energy production and regulation permit condition.

$$\begin{cases} (1)\ Q_i \geq Q_{i,min} \\ (2)\ Q_i \leq Q_{i,max} \\ (3)\ P_i \leq P_{i,max} - C_{FCR-N} - C_{FCR-D} - C_{FRR}^{+} \\ (4)\ P_i \geq P_{i,min} + C_{FCR-N} + C_{FRR}^{-}. \\ (5)\ |\Delta Q_s| \leq Q_{s,max} \\ (6)\ h_r \leq h_{r,max} \\ (7)\ h_r \geq h_{r,min} \end{cases}$$

First four boundary conditions are related to energy production. Hydro unit i available discharge capacity is restricted by minimum ($Q_{i,min}$) to maximum discharge ($Q_{i,\max}$). Similarly, production output (P_i) must be in the range set by minimum (P_{min}) and maximum production output (P_{max}) but also possible reserve capacities (C_{FCR-N}, C_{FCR-D} and C_{FRR}) must be noticed as presented in conditions (3) and (4). In those conditions, FRR capacity refers to any reserve capacity that have been cleared before intraday market for the hour in question closes. Basically these markets are aFRR and Fingrid's balancing capacity market.

Last three conditions are related to possibility to alter discharge. Condition (5) can set limitation how discharge of a hydro plant s can be altered between hours. Condition might be set by plant's permit but also other constraints might be agreed on the issue. Moreover, altering of production must be done in a way that minimum ($h_{r,min}$) and maximum reservoir level ($h_{r,max}$) are not infringed. Presented boundary conditions are in hourly basis but there might be need to consider that day average flow through hydro plant fulfills the permit conditions, for instance.

Hydro system's unused hourly capacities for both directions are calculated automatically in the EMS and then used to form the basis for bidding curves. Calculation is based on the available hourly energy production capacity ($E^{C}_{buy,h}$ and $E^{C}_{sell,h}$) which is basically same as conditions (3) and (4). However, in real-world operation of small sized reservoirs, the available reservoir content given conditions (6) and (7) should not be neglected. Hence, the available hourly bid might be restricted based on the reservoir plan as was presented in the chapter 5.1.3. The volumes are determined as

$$E_{buy,h} = Min\left(E^{C}_{buy,h}, E^{r}_{buy,h}\right) \tag{20}$$

$$E_{sell,h} = Min\left(E^{C}_{sale,h}, E^{r}_{sale,h}\right), \tag{21}$$

where $E^{r}_{buy,h}$ and $E^{r}_{sell,h}$ are estimated feasible energy volumes (MWh) of the reservoir r. They are based on the available reservoir energy content of the bidding hour but also for latter hours content in order to maintain permit conditions of the reservoir without undesirable error in power balances. When we estimate those, we take the water delays between the hydro plants into account as was presented in chapter 4.3.3. Energy production capacities $E^{C}_{buy,h}$ and $E^{C}_{sell,h}$ are calculated with following equations.

$$E^{C}_{buy,h} = E_{plan} - C_{FCR-N} - C_{FRR} - P_{min} \tag{22}$$

$$E^{C}_{sell,h} = P_{max} - E_{plan} - C_{FCR-N} - C_{FCR-D} - C_{FRR} \tag{23}$$

Once we have estimations of the unused production flexibility, we can determine prices related to each bidding points. In some circumstances of cascade hydro plant operation, it might be profitable to spill water from one hydro plant. For instance, this might be the case when the energy price is enough high and otherwise other hydro plants could not meet the attractive energy price.

5.3.1 Bidding points

In practice, determining the bidding points for a cascade hydro system with small reservoirs is a compound question. Decided bidding points should lead to gain more profit from production flexibility when deviating from original plan such as day-ahead commitment. This requires excellence in forecasts of reservoir content and future prices but also accurately modelled hydro units' properties.

An example of theoretical bidding point selection for production increase is presented in Figure 41. The bid curve (red points in Fig 41.) is based on the marginal cost of production increase like presented in the chapter 4.4. In the example, the hydro plants *P1 – P4* are modelled as a one hydro plant by combining their average and marginal cost curves into one bid curve. The original working point is randomly chosen to be in the best-point production in way that only one unit per hydro plant is dispatching.

The example is purely based on the efficiency losses of production because we do not take the cost of start-up into account. In addition we assume that the overall working area is available which could be in reality be unrealistic assumption due to a water balance of the reservoir, for instance.

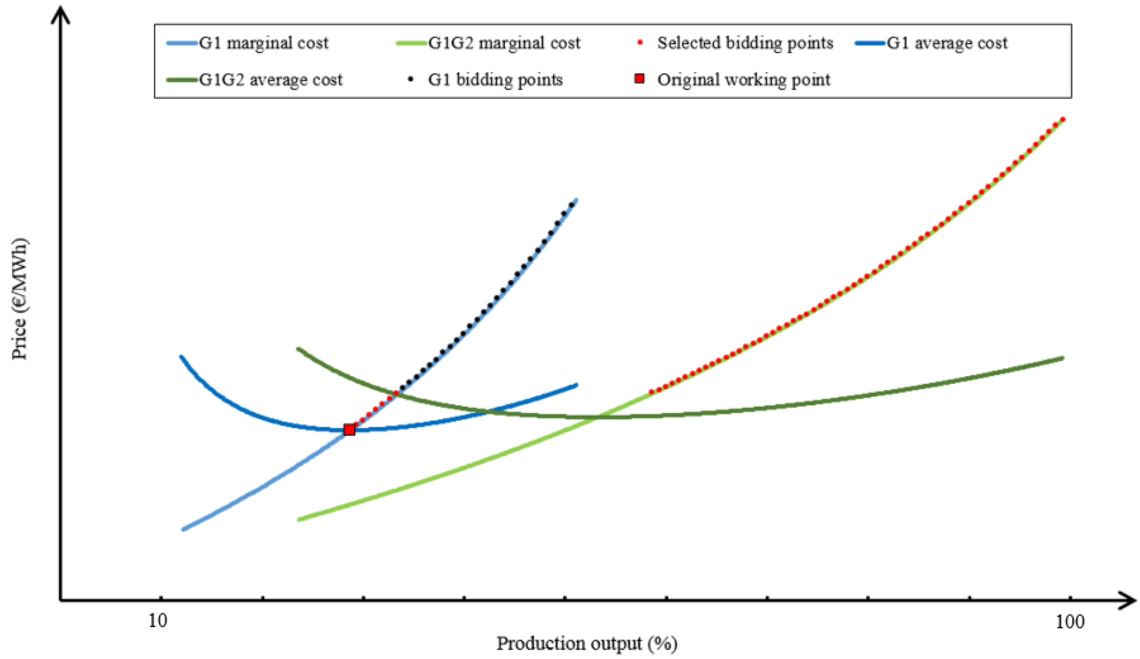

Figure 41. *Selection of bidding points based on the production efficiency and production range without any reserve obligations or deviation cost.*

As we can see from the figure's bidding curve, the hydro plant have capacity to both directions. With this bidding curve, the part above the original working point is the quantity of energy that the producer is willing to sell and produce when the energy price is at least the bidding value or higher. The bid curve in the figure (red points) is ideal bid curve from an efficiency point of view because we directly move to the another unit combination (G1G2) once its average cost is equal to the marginal cost of the original unit combination (G1). In reality, this would not be optimal solution due to start-up costs and therefore it would be advisable to take some of the original unit combination's bidding points (black points in Fig. 41) into account before moving to the another unit combination. The part of the curve below the original working point is the amount of energy that the producer would not be willing to produce if the energy price is at the bidding value or lower.

In the studied river system, there are total of 11 hydro turbines in five hydro plants. For simplicity, it can be assumed that hydro turbines in the same hydro plant are identical, as proposed in the chapter 4.4. Therefore there is actually five different type of hydro units, one of each plant, from which all of the possible combinations i.e. bidding curves can then be modified. For instance, a possible bid could be based on the assumption that all of the hydro units are utilized to meet power increase or decrease caused by bid acceptation. Additionally, bid points could be based on any other combination, such as on assumption that only one of the hydro units alter its production in accordance with the bid volume. When creating bids, we need to consider which of the hydro units are dispatched if bid is accepted so that the estimated marginal cost is in reality reflected in the pricing of the bids.

In addition to the hourly marginal pricing of the hydro production, it might be reasonable to consider how one or multiple hours' production altering from the original plan should be taken into account in the studied river. Basically two cases are relevant to discuss. We assume that production and reservoir levels are realized as planned if there are no energy trades done in intraday or balancing power markets. Then if producer trades during the day of operation, it most probably have some influence on the reservoir levels in hour in question but also in the sequential hours. Therefore it might be reasonable to assume that the production efficiency will be differing from the day-ahead market obligation when one or more of the hydro units runs with different head level than originally planned. Basically, a hydro unit operating with higher head uses less water than the same unit with lower head when producing the same amount of energy. Thus, as a result of realized trade utilization, a hydro unit might start using more water than planned or vice versa when producing the planned energy. Figure 42 shows how an increase in production in one hour influences the reservoir level when hydro plant's inflow has not increased.

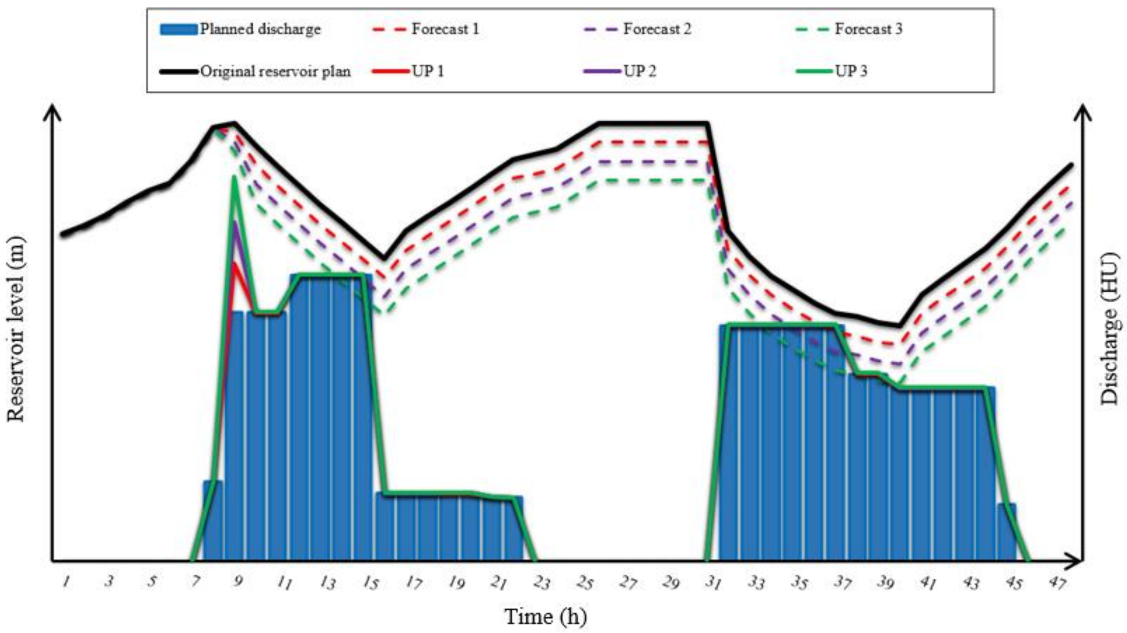

Figure 42. *Impact of the production altering to the reservoir of hydro plant P5. UP denotes increase of production.*

Planned hourly reservoir usage and discharge of the hydro plant P5 is shown in Figure 42. In addition, the figure shows three additional reservoir level forecasts (1 to 3). In this example, production is modelled to be increased at hour 8 with three different volumes.

These production increases are 5 MW, 10 MW and 15 MW. They are presented as corresponding discharges in Figure 42. Once production is increased, reservoir level changes in accordance with the additional usage of water. Three different forecasts show how the reservoir level behaves in the different cases of production increases if the rest of the time period is produced as originally planned.

Reservoir level declining by the production increase in one or more hours will cause that the unit discharge is slightly higher in the sequential hours than was planned beforehand. If production is increased only in hour 8, unit will need, depending on the production increase, from 2 to 7 HU more water during the rest of the hours of the operation day. This is caused by the efficiency change. The issue will be discussed next.

When producing more energy than originally planned in the day-ahead commitment, the sold energy could be priced in accordance with the marginal cost curve presented in Figure 41. In addition, the efficiency change of the latter hours should be considered because increased water usage in one or more hours decreases reservoir level of hydro unit (see Fig. 42). This in turn increases the needed water for producing day-ahead commitment during sequential hours. In this case the water value received from day-ahead commitment might be decreased. For this purpose, producer need to consider how much reservoir levels changes with different realized bid volumes.

Furthermore, it should consider at what hour production can be decreased and therefore water be saved. In the described case, hydro unit uses more water than originally planned until the used water is compensated and the hydrological situation is returned to meet the original plan. It is noteworthy that the need and timing of described production compensation by saving water is crucial for the hydro system's overall profitability. By the need is referred to certain cases where there is no need to decrease production from any of sequential hours due to increased water inflow to the one or both of the reservoirs $P1$ and $P4$. Naturally, in a such situation, the marginal price of water might be decreasing due to increased water availability. By the timing is referred to hours in which production can be decreased with respect to any binding condition.

Basically, the cumulative energy loss increases with time, i.e. the amount of lost water depends on the length of time which hydro plant's reservoir is lower than planned (reservoir deficit). Since lowered reservoir level increases needed discharge, tail water level also increases. We could assume that the needed amount of power decrease is invariant during the considered time period (T): for instance, if we estimate that the production needs to be decreased by 10 MWh during the operation day in order to meet tomorrow's target reservoir content, the decrease in the sequential hour ($t + 1$) as well as some other future hour such as ($t + 12$) causes that the reservoir level returns to be in accordance with the original plan. In reality, this assumption overlooks additional reservoir usage caused by an increased need for discharge. In other words, it assumes that the sequential hours' water usage is in line with the original plan which should not be true due to the increased need for discharge. Hence, the sequential hours' production efficiency is lower than is assumed in the original plan. In order to overcome this incorrect estimation, one can estimate latter hours' water usage in an hourly basis based on reservoir level at the beginning of the sequential hour $(t + 1)$ and planned energy in the hours of the time period. Once there is estimation about the amount of additional water usage, it can be priced with the help of the future water cost.

Efficiency change, positive or negative, caused by changed reservoir level can be taken into account by introducing a head-depended factor α. For a given production output, this head-depended factor influences the production output-input curve by increasing or decreasing the needed input which basically is needed discharge. Since we consider intraday bidding, we have a production plan, forecasted net head and reservoir level plan as starting points. Thus we can estimate how much net head level of some hour changes from the original plan with different bidding volumes. The factor can be calculated based on energy adjustment and hydro plant's reservoir's energy content, storing capacity factor and net head with following equation

$$\alpha = \frac{\frac{\Delta E}{Energy\ content} \Big/ Storing\ capacity\ factor}{NH} \tag{24}$$

where

ΔE is an amount of adjusted energy from original production plan (MWh)

$Energy\ content$ is hydro plant's reservoirs energy per volume (MWh/HU)

$Storing\ capacity\ factor$ for hydro plant's reservoir in (m/HU)

NH is net head of hydro plant (m).

In the equation (24), $energy\ content$ is the amount of energy that is received from a hydro plant with one HU of water. $Storing\ capacity\ factor$ defines how much reservoir level changes with the difference between the hydro plant's outflow and inflow. Both $energy\ content$ and $storing\ capacity\ factor$ are dependent on the reservoir level or reservoir content.

Head-depended factor gives an estimation on how much a hydro plant's head level changes in per cent due to changed reservoir level of the plant. If we assume that the hydro unit's discharge is linearly dependent on the net head, we can use the factor to calculate an increase or decrease of the discharge. For instance, head-depended factor of 0.005 implies that hydro unit uses hourly 0.5 % more or less water than originally planned when producing the production plan. The factor gets positive values always when the reservoir level is changed from the original plan because in production increase, it includes lost water to bid price and therefore causes higher price and similarly in production decrease, the factor includes saved water to bid value which basically enables producer to sell more energy in future than was planned beforehand.

Now we have estimated how the efficiency of production changes based on the reservoir deficit in one hour but actually we need to estimate the cumulated losses in the time period of latter hours. A straightforward solution is to calculate alpha in an hourly basis for future time period (T) in order to estimate the cumulated costs of the period. When calculating the factor for the future hours from $t+1$ to the end of the period, the only changing term is the hourly changing net head because we assume that the reservoir's level change is caused by the bid realization in hour t.

So, the actual bid price for an operation point p is the sum of the marginal cost of the operation point and the value of saved or lost water in the latter hours.

$$B_{cst}^{p} = mc_{cst}^{p} + \sum_{t=t+1}^{T} \left(\alpha(t) \cdot q_{planned}(t)\right) \cdot WC_{st} \tag{25}$$

B_{cst} is bid price of a operation point p

mc_{cst}^{p} is marginal cost of a operation point p

$q_{planned}$ is planned discharge in hourly resolution

WC_{st} is water cost of a future period such as next day-ahead period.

In reality, the presented method might be an inaccurate way to estimate latter hours' efficiency change because we do not take the tail water level behavior into account. On the other hand, the realization of bids in the latter hours is unknown when bidding in the first hour and moreover, the time period is somewhat unknown because in intraday markets prices are volatile which in turn might enable producer to compensate the adjusted energy faster than was estimated. Nevertheless, the amount of lost water caused by the efficiency decrease, depends on the time period and planned discharge during that time period. This means that the amount of lost water increase with longer time period and higher discharge level. For this reason, it might be reasonable to consider when a reservoir is filled up to the planned level in order to estimate the cost caused by the changed production efficiency. For the hydro system in question, a good assumption of the maximum period is the end of the next day-ahead period because the hydro reservoirs are relatively small-sized.

An example of bid curve calculation for one days' hours 08:00 – 09:00 to 14:00 – 15:00 is presented in Figure 43. For simplicity, the example is based on the production bidding of hydro plant *P5* with three working units. The basis for the calculation is in the same production plan that was presented in Figure 42 earlier. The bid curves are determined with the following way. Firstly, we calculated bids without considering the impact of one hour production altering on consecutive hours. Then to emphasize the effect of the introduced alpha, we calculated one hour's bid curve also with estimated efficiency losses during the consecutive hours of the operation day. This is reasonable assumption for the time period at least in this case because the production of the hydro plant cannot be decreased from the evening hours from 15:00 to 23:00 due to its production level and reserve obligation. Therefore we have used the next day's water cost as the opportunity cost when pricing the cumulated losses.

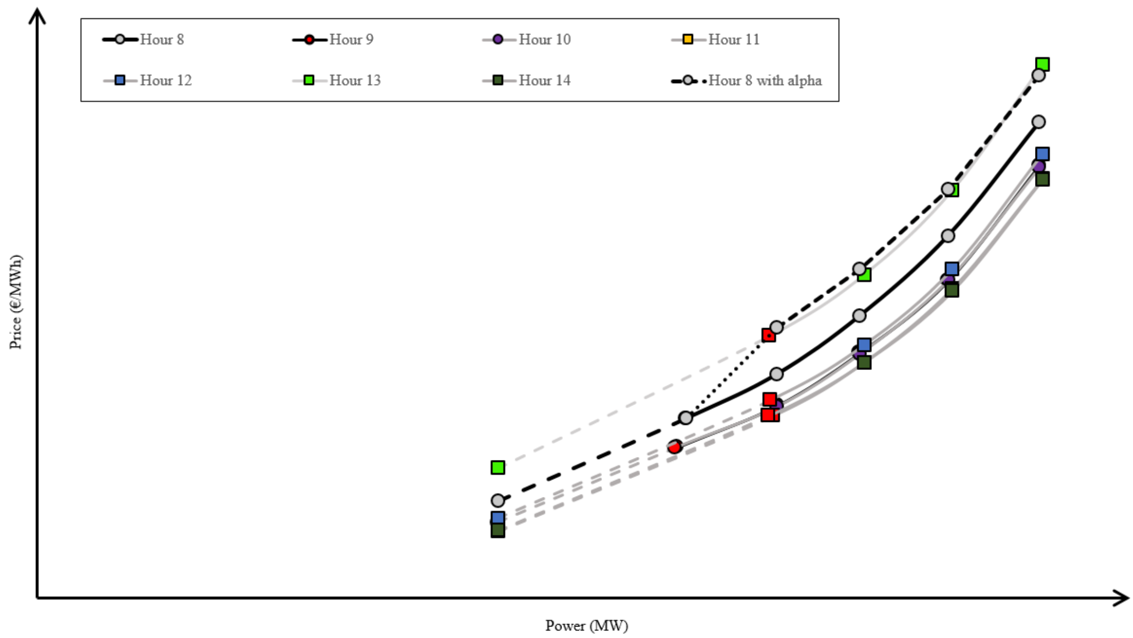

Figure 43. *An example of bid curves for production increase. For comparison purposes, there is one bid curve (dashed line named "hour 8 with alpha") that takes latter hours production efficiency into account.*

In Figure 43, the red marks denotes each hours' original operation point given by day-ahead market commitment. The points below the original operating points are the ones where the hydro plant maximizes its production efficiency, i.e. $ac_{cst}^{p} = mc_{cst}^{p}$ as was earlier presented in chapter 4.4. The bidding points above the original production plan are based the marginal cost of production. In the curves of the figure, production increase is shown in 5 MW steps. As we can see from Figure 43, introduced alpha increases slightly the price related to bid volume due to efficiency losses during the consecutive hours.

In the previous example it is assumed that hourly production is in perfect agreement with reservoir's marginal water value. Therefore, production bidding is based on the hours' operation point, day-ahead price and marginal cost curve. In the complex river system with multiple nearly run-of river hydro units, the assumption is not realistic due to reservoir balances and topology constraints: some hour's received water value is higher than some other because of the hydro system constraints. Moreover, if day-ahead bid does not consider stochastic nature of price, some hour's commitment might be differing from optimal commitment. In the river system in question, this issue can be tackled by evaluating the marginal water value of the reservoirs and by using these values as the basis of the bidding but it is not treated in this thesis.

5.3.2 Intraday market monitoring

This chapter illustrates how intraday market monitoring can be utilized in intraday production scheduling. By monitoring intraday market, producer can find bids that are favorable for it but also evaluate the opportunity cost for a production increase or decrease based on the intraday market. In addition, the chapter presents how available production capacity and energy content in reservoirs influence on the possibility to trade in the intraday market.

Because the producer aims to increase its profitability with its unused production flexibility when profitably applicable, monitoring of intraday market bids could be beneficial when considering cases in which market volatility is utilized by production increasing in one hour and then decreasing in some future hour, for instance. This monitoring would also, at least in theory, reduce producer's risk of uneconomically pricing the balancing power or intraday market bids. This is emphasized with nearly run-of-river hydro plants, like the hydro plants studied in this thesis, when the water availability is low because in such circumstances producer might be forced to buy energy during the day of operation if it uses reservoirs for up-regulation. Underpricing of the scarce water means that profits are lost, but on the other hand overpricing will also lead profit reduction since possibilities might be missed.

Monitoring of intraday market can be done automatically without any human effort with control center's software program that is integrated to EMS and the intraday market platform via Nord Pool's Application Programming Interface (API). Available intraday market data (bids) makes it possible to evaluate at hourly basis what price a certain energy volume can be bought or sold in the market place. In addition to hourly consideration, producer may find favorable bids within some time period to get more economical result than what could be achieved by only one hour production altering. Combining this data of available bids in the market with hydro units technical limitation, reserve obligations and water permits, producer can value a certain volume that can be bought or sold in the intraday market in a way that any of the obligation mentioned are not infringed. For this purpose, control center has variables in its EMS that automatically calculate available production capacity to both directions in generator-specifically as was presented in the beginning of chapter 5.3.

To emphasize production allocation possibilities with respect to intraday market demand situation, we present two different cases. In these cases, we try to demonstrate how the producer could automatically estimate the energy prices of production increase or decrease if it is willing to done it by trading in intraday market. We form price by volume curves for sell and buy for both cases based on the bids in the market and available capacity of the hydro units. In both cases, producer tries to estimate at what price it can decrease or increase its production from 5 MWh up to 50 MWh in the upcoming 14 hours period. For simplicity, we do not include the marginal cost of production to the examples. Afterwards we consider how the results of the cases would change if we would have included marginal cost consideration in the calculation.

In the first case, production re-scheduling is quite restricted whereas in the second case there is more flexibility available. The cases are based on the actual intraday market situation that was prevailing in the day of the examination. In the first case, the trading capacity comes from the unused flexibility of hydro plant *P5*. The second case's trading capacity is available capacities of all hydro plants (*P1 – P5)*. These energy trading capacities are presented in Table 4. Values are shown at accuracy of 5 MW.

Table 4. *Available hourly production capacities.*

	Hydro plant P5 (case 1)		**All hydro plants (case 2)**	
Hour	UP (MW)	DOWN (MW)	UP (MW)	DOWN (MW)
09	0,00	20,00	10,00	40,00
10	0,00	20,00	15,00	35,00
11	0,00	20,00	15,00	35,00
12	5,00	20,00	15,00	35,00
13	5,00	15,00	15,00	35,00
14	5,00	15,00	15,00	35,00
15	5,00	15,00	15,00	35,00
16	5,00	15,00	15,00	35,00
17	5,00	15,00	15,00	35,00
18	5,00	15,00	15,00	35,00
19	5,00	15,00	15,00	35,00
20	5,00	15,00	15,00	35,00
21	15,00	0,00	35,00	20,00
22	15,00	0,00	35,00	0,00

Let us consider the case 1 first. As we can see from Table 4, there is no upward trading capacity available in hours 09 – 12 and similarly, there is no possibility to decrease production during the last two hours. The hours 12 – 21 enables producer to alter production in both directions if the water balance do not restrict it. The situation changes remarkably in the case 2 where there is clearly more available production capacity to be utilized.

Once we have determined hourly production capacity that could be also restricted by reservoir content as presented in equations (20) and (21), we find the most feasible bids in the market place. The price-volume curves for the first case are presented in Figure 44 where the sell price curve determines the energy prices for production increase and respectively, the buy price curve estimates the cost for production decrease.

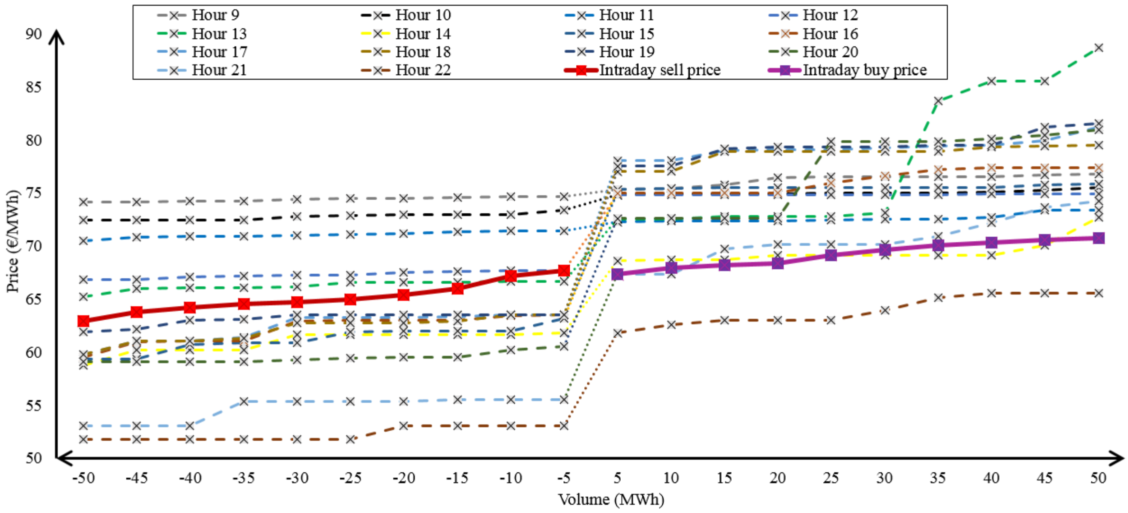

Figure 44. *Determining of available selling- and purchase price for hydro unit P5 based on intraday market. Hourly prices are as they were in the market place. Price-volume curves are average from the bids that are in reality available for the production re-scheduling.*

As the example in Figure 44 shows, producer cannot necessarily utilize the best available intraday market's prices which were in this example available in hours 09 – 12. It is, though, natural that the hydro plant's production is at its highest level when the day-ahead prices are the highest and similarly production is at its lowest level when the day-ahead prices are the lowest. Thus, the intraday flexibility of the hydro plant in this case is naturally restricted.

The result of the example changes remarkably when considering the case 2 due to increased available production capacity. This is shown in Figure 45.

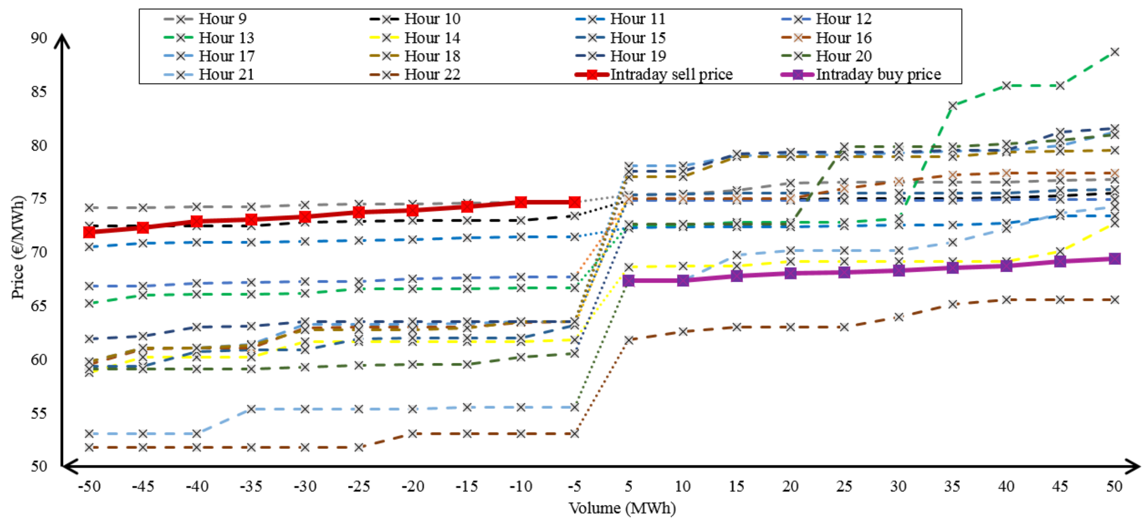

Figure 45 *Determining of available selling- and purchase price for the hydro system based on intraday market supply and demand. Hourly prices are as they were in the market place. Price-volume curves are average from the bids that are in reality available for the production re-scheduling.*

The difference between Figures 44 and 45 is clear: the latter case is more favorable for the producer due to its price-volume curves. In the latter case, producer have more hours in which it have capacity to both directions but also available volumes are higher which enables more profitable trading possibilities. Energy prices related to both cases are presented in Table 5. The values are the same as shown in Figures 44 and 45.

Table 5. *Price-volume curves.*

	Case 1			Case 2		
Volume	Sell (€/MWh)	Buy (€/MWh)	Spread (€/MWh)	Sell (€/MWh)	Buy (€/MWh)	Spread (€/MWh)
5 MW	67.20	66.80	0.40	74.10	66.80	7.30
10 MW	66.65	67.45	-0.80	74.10	66.80	7.30
15 MW	65.43	67.70	-2.27	73.68	67.23	6.45
20 MW	64.83	68.71	-3.88	73.38	67.47	5.91
25 MW	64.46	69.33	-4.87	73.19	67.62	5.57
30 MW	64.22	69.77	-5.55	72.81	67.78	5.03
35 MW	63.99	70.09	-6.10	72.53	67.98	4.55
40 MW	63.65	70.34	-6.69	72.32	68.19	4.13
45 MW	63.25	70.54	-7.29	71.75	68.58	3.17
50 MW	62.42	70.92	-8.49	71.29	68.90	2.39

We can see from Table 5 that the production can be sold with clearly higher price in the second case than in the first case. This difference becomes greater with higher volumes. For instance, production increase of 10 MWh can be done with 7,45 €/MWh higher energy price in the latter case than in the first case. Similarly, production decrease is more favorable in the second case because production can be bought from the market place with slightly lower price. In addition, in the first case there is no favorable price spread, i.e. sell and buy difference, to be utilized and thus there is no possibility to increase profits by producing more in one hour and less in another hour.

However, the hours cannot be necessarily treated equally, because the production level, hydrological situation and generator combination do in reality vary throughout the time period. Hence, rational trading decision must be based on water value rather than purely on the energy price like was presented in the examples. Thereby, the marginal cost of production and latter hours' hydrological balance should be included in the decision making process. So, based on the planned energy production of the hour, it is possible to determine the marginal cost for increment of energy, piece by piece for the whole available capacity calculated in equations (20) and (21). By adding this marginal cost examination to the intraday market data, the water value can be maximized. Thus, the best available intraday market prices are not necessarily the most attractive ones in the eyes of the hydro producer, the question is rather how water is allocated most profitably.

In the first case, producer has no possibility to create value by intraday market trading if we only consider the examples hours and intraday market alone. The second case is promising even though we would take marginal cost of production into account, because of its buy and sell curve values shown in table 5. With the example's intraday market bids, the second case's solution would be identical from the production allocation point of view even if we take marginal cost with sequential hours efficiency change into account. However, profits would be declining from what is shown in the table 5 because of the decreased efficiency. It is though noteworthy to underline that the efficiency change is not as remarkable in the case 2 than what it would be in the case 1 because in the second case there are multiple hydro plants that can be utilized in the increase or decrease of the energy production.

The question that a producer commonly faces in intraday market is related to the decision time: how prices will develop when moving towards the closing time of one trading hour? As Figures 44 and 45 above illustrates, the bid-ask spread is small with near future hours but increases when moving further in hours. Hence, the hydro producer might consider when is the right time to close a trade based on the combination of price fundaments and personal knowledge on the market behavior. These driving fundaments of intraday prices can for instance be realized balancing power prices, planned or unplanned production/consumption unavailability of some market participants, i.e. Urgent Market Messages, or change in weather conditions which mediates to weather depended consumption and production. To clarify these weather conditions, weather depended consumption is related to heating demand and therefore it might be relevant especially during high consumption in winter. Moreover, weather depended wind production is exposed to forecast error, for instance. It is noteworthy though to remember that the presented type of bid-ask spread is not the only truth when considering how intraday market works.

6. CONCLUSION

In this thesis, previously unknown hydro system and its properties were studied as a part of a project in which the hydro system's physical planning and operating were taken over by a control center. During the project, all the needed properties of hydro system planning and operating were covered and trained to the personnel in order to continue safe and profitable regulation of the hydro system. Gathering of practical knowledge about the hydro system properties will increase profitability of the river production. This thesis was in key role in studying of those properties and developing of intraday energy bidding but also for training process of the personnel.

In successful hydro production tasks, the control center needs different tools but also good practical knowledge. It is reasonable to assume that both of them will develop further once actual operating experience is gathered. From the control center's point of view, it is highly important that tools are well-working because that enables Intraday Traders to focus on other issues like trading in the intraday market rather than continuous controlling of the river production. In general, forecast and optimization tools can be adjusted step-wisely in future. This also implies to the method considered to be used in intraday bidding.

In this thesis, a method for intraday bid generation is presented. The method considers production efficiency in relation to the marginal value water. In addition, the change in production efficiency in consecutive hours is somewhat included in the method. It is achieved by assuming that the hydro plant's head level differs from original plan during the consecutive hours. This will at least in theory increase the accuracy of the estimation on the deviation cost that arises when production is adjusted from the previously optimized plan such as the original day-ahead plan. However, there are uncertainties like future energy price related to the method. At the moment, there is no fully completed tool based on the method available for intraday bid generation which makes it difficult to analyze the quality of the method. Still, the bid calculation seems to be a very promising way to form bidding curves. Nevertheless, marginal cost curve based bidding is easily implementable to bidding tools now because each and every one of the hydro units' properties have been studied and converted into marginal cost curves. Modelled marginal cost curves can be used also in day-ahead bidding when considering hourly price depended bidding.

To be able to add value by continuous intraday market or balancing power market trading, the hydro producer like any other market participant in those markets, needs to evaluate its production flexibility's price and volume in an hourly basis. Results of this thesis enable the control center to evaluate those in real-time. Moreover, intraday market monitoring with respect to available energy trading capacity could be increased and therefore added value could be increased by accepting favorable bids from the market place, for instance. This was emphasized with two different example cases in which we demonstrated the opportunity cost of the production increase or decrease that would be achieved by intraday market trading. The examples show how available production flexibility can increase the hydro system's profitability. This is though natural in the electricity market where the profitability increases with flexibility. Additionally, we can conclude that it would be possible to use intraday market bids as one input to the day-ahead optimization framework: the day-ahead optimization framework could seek to optimize production plan from the hours where it sees that intraday market prices are favorable for re-scheduling.

Studied hydro system's flexibility is good from intraday point of view due to short delays between the units, but also due to two quite large plant reservoirs, at least in respect with the rest of the plant reservoirs. In addition, the higher discharge capacity of hydro plant P5 increases flexibility. However, it seems that the bidding flexibility can be increased by developing optimization tools and models further. For instance, production allocation between hydro plants could perhaps be utilized more efficiently if water delays between hydro plants *P1* to *P4* are added to optimization model. On the other hand, changing production level at every hour can be laborious for the Intraday Traders and economically questionable with small price differences between hours. Therefore besides more economically efficient production allocation stated before, accurately modelled water movement could enable automated production control in future and thus increase the profitability of production altering between hours since it could be done without any human effort.

In the future, the control center needs to consider how the intraday bidding can be connected to the day-ahead optimization. Currently, available intraday production capacity is priced by the control center's expert judgement. It does not necessarily lead to wrong evaluation but the question is more on how pricing can be automatized further. One simply way could be to divide plants' reservoirs to cuts in which all have its own water value. Then these cuts of water value determine at what price the producer is willing to dispatch or save water. The values could be used as a basis for the intraday bidding. It must be noted that with small-sized reservoirs, water value might be differing remarkably due to one or two hour altering of production. In addition, the values are sensitive for errors in inflow. Forecast error in reservoir level might cause error in water value and lead to undesirable situation in later hours of operation. Hence, in order to be able evaluate plant reservoirs' marginal water value, it is important to know accurately the amount of arriving water to reservoirs *P1* and *P4*. One way to improve inflow estimation would be flow meters. These meters could be used to flow measurement at least in the side-stream above plant *P4* and in river part between plant *P1* and reservoir *R3*.

Coordinated bidding is quite a hot topic today in hydro power studies due to changes in both power production and expanding energy markets. Increasing amount of vRES and decreasing amount of controllable energy production such as condensing power together in the strengthening power grid will increase possibilities in the reserve and intraday markets. Therefore, control center needs to develop its bidding strategies to cover all available reserve and energy market places. Especially with nearly run-of-river production, marginal water value is effected by expectations on available water in reservoirs and day-ahead price but also forecasted prices in reserve, intraday and balancing power markets. However, valuing of water was not in the scope of this thesis and thus more research is needed to cover this topic. It would be interesting to see how this particular river system's profitability would develop if bidding would be done in a more coordinated way than today.

By the end of year 2020, the imbalance settlement period is switched to 15 minutes in all EU member states. This is required by the energy balancing network code. Simultaneously, intraday and balancing power markets transfer to 15-minute trading period. (Fingrid 2019c) Nordic TSOs' are aiming to implement the change by the end of year 2020 but there is a risk that the implementation will be delayed (Fingrid 2019d). From the hydro producer's control center point of view, the shorter imbalance settlement period makes automated bid calculation for intraday and balancing power markets a necessity. In addition, automated monitoring of intraday market might become more and more important because it is not realistic that a human could monitor the market continuously while performing other tasks.

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